PETRO-CANADA

PETRO-CANADA ANNUAL INFORMATION FORM 2004

March 15, 2005

ITEM 2 – TABLE OF CONTENTS

Table of Contents

*Marque de commerce de Petro-Canada – Trademark

Conversion Factors

To conform with common usage, imperial units of measurement are used in this report to describe exploration and production, while metric units are used for refining and marketing. Dollars are Canadian, unless otherwise stated. All oil and natural gas production and reserves volumes are stated before deduction of royalties, unless otherwise indicated.

1 cubic metre (liquids)	=	6.29 barrels
1 cubic metre (natural gas)	=	35.30 cubic feet
1 litre	=	0.22 imperial gallon
1 square kilometre	=	247.10 acres
1 hectare	=	2.47 acres
1 cubic metre	=	1,000 litres

Non-Generally Accepted Accounting Principles (GAAP) Measures

Cash flow, which is expressed before changes in non-cash working capital, is used by the Company to analyze operating performance, leverage and liquidity. Earnings from operations, which represent net earnings excluding gains or losses on foreign currency translation, disposal of assets and unrealized gains or losses on the mark-to-market of the derivative contracts associated with the Buzzard acquisition, are used by the Company to evaluate operating performance. Cash flow and earnings from operations do not have a standardized meaning prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures for other companies.

Legal Notice – Forward-Looking Information

This Annual Information Form (the AIF) contains forward-looking statements. Such statements are generally identifiable by the terminology used, such as "plan," "anticipate," "intend," "expect," "estimate," "budget" or other similar wording. Forward-looking statements include, but are not limited to, references to future capital and other expenditures, drilling plans, construction activities, the submission of development plans, seismic activity, refining margins, oil and natural gas production levels and the sources of growth thereof, results of exploration activities, and dates by which certain areas may be developed or may come on-stream, retail throughputs, pre-production and operating costs, reserves estimates, reserves life, natural gas export capacity and environmental matters. These forward-looking statements are subject to known and unknown risks and uncertainties, and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies; fluctuations in oil and natural gas prices; refining and marketing margins; the ability to produce and transport crude oil and natural gas to markets; the effects of weather conditions; the results of exploration and development drilling and related activities; fluctuations in interest rates and foreign currency exchange rates; the ability of suppliers to meet commitments; actions by governmental authorities including increases in taxes; decisions or approvals of administrative tribunals; changes in environmental and other regulations; risks attendant with oil and gas operations; and other factors, many of which are beyond the control of Petro-Canada. These factors are discussed in greater detail in filings made by Petro-Canada with the Canadian provincial securities commissions and the United States (U.S.) Securities and Exchange Commission (SEC).

Readers are cautioned that the foregoing list of important factors affecting forward-looking statements is not exhaustive. Furthermore, the forward-looking statements contained in this AIF are made as of the date of this AIF, and Petro-Canada does 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. The forward-looking statements contained in this AIF are expressly qualified by this cautionary statement.

Petro-Canada's staff of qualified reserves evaluators generates the reserves estimates used by this Company. Our reserves staff and management are not considered independent of the Company for purposes of the Canadian provincial securities commissions. Petro-Canada has obtained an exemption from certain Canadian reserves disclosure requirements to permit it to make disclosure in accordance with SEC standards in order to provide comparability with U.S. and other international issuers. Therefore, Petro-Canada's reserves data and other oil and natural gas formal disclosure is made in accordance with U.S. disclosure requirements and practices and may differ from Canadian domestic standards and practices. Where the term barrel of oil equivalent (boe) is used in this AIF, it may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet (Mcf): one barrel (bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

The SEC permits oil and gas companies, in their filings with the SEC, to disclose only proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. The use of terms such as "probable," "possible," "recoverable" or "potential" reserves and resources in this AIF does not meet the guidelines of the SEC for inclusion in documents filed with the SEC.

ITEM 3 – CORPORATE STRUCTURE

Incorporation of Petro-Canada

Petro-Canada is a corporation incorporated under the *Canada Business Corporations Act*. Throughout this AIF, the terms "Petro-Canada," the "Company," "we," "us" and "our" refer to Petro-Canada and its subsidiaries or, where the context requires, the applicable business unit within Petro-Canada (i.e. North American Natural Gas, East Coast Oil, Oil Sands, International and Downstream).

The registered and principal executive office of the Company is located at 150 - 6 Avenue S.W., Calgary, Alberta, Canada T2P 3E3. Telephone: (403) 296-8000.

By-Law No. 2 of the Company was initially implemented upon the privatization of Petro-Canada and initial public offering of common shares in 1991. By-Law No. 2 was subsequently revised in 1995 upon the sale by the Government of Canada of 50% of Petro-Canada's outstanding shares. The purpose of By-Law No. 2 was to address matters in relation to Directors designated to serve on the Board of Directors by the Government of Canada. In September 2004, the Government of Canada sold its remaining interest in Petro-Canada. As a result, By-Law No. 2 of the Company has been rendered ineffective by its own terms, due to the fact that the Government of Canada is no longer the registered holder of 10% of the voting shares of Petro-Canada.

Intercorporate Relationships

Material operating subsidiaries owned 100%, directly or indirectly, by the Company as at December 31, 2004, were as follows:

Name	Jurisdiction of Incorporation	Purpose
3908968 Canada Inc.	Canada	A Canadian subsidiary holding Petro-Canada's International interests.
Petro-Canada U.K. Holdings Ltd.	United Kingdom (U.K.)	A subsidiary of 3908968 Canada Inc. that holds Petro-Canada's U.K. interests.
Petro-Canada U.K. Limited	U.K.	A subsidiary of Petro-Canada U.K. Holdings Ltd. through which Petro-Canada's operations are conducted in the U.K.
Petro-Canada Energy North Sea Limited	U.K.	A subsidiary of Petro-Canada U.K. Limited that holds Petro-Canada's interest in the Buzzard oilfield in the U.K. sector of the North Sea.

Individually, the Company's remaining subsidiaries account for less than 10% of the Company's consolidated revenues and consolidated assets. In the aggregate, they account for less than 20% of the Company's consolidated revenues and consolidated assets.

ITEM 4 – GENERAL DEVELOPMENT OF THE BUSINESS

Three-Year History

The following is a recent history of major Company events:

2004

From both a financial and strategic point of view, 2004 was a strong year for Petro-Canada. Specifically, the Company:

- achieved record earnings from operations of $1.9 billion and record cash flow of $3.7 billion;
- met upstream production targets;
- acquired interests in the U.S. Rockies and the U.K. sector of the North Sea, positioning Petro-Canada for future growth; and
- completed most of the work to consolidate Eastern Canada refineries and increased sales at convenience stores and of high-margin lubricants.

During 2004, North American Natural Gas extended its footprint into the U.S. Rockies with the acquisition of Prima Energy Corporation (U.S. Rockies) for $644 million, net of acquired cash. This acquisition added 55 million cubic feet equivalent per day (MMcfe/d) from coal bed methane in the Powder River Basin and from tight gas in the Denver-Julesburg Basin, and significant expertise in unconventional production.

Petro-Canada also expanded its International position with the acquisition of a 29.9% interest in the Buzzard project and the progression of the Pict and De Ruyter developments in the North Sea. The Buzzard field has estimated life of field reserves of 550 million barrels (MMbbls) of oil, with Petro-Canada's share of peak production expected to reach 60,000 boe/d in 2007.

Petro-Canada is seeking to participate in the global liquefied natural gas (LNG) business, consistent with its objective to add long-life producing assets to its portfolio. In September 2004, a Memorandum of Understanding (MOU) was signed with TransCanada PipeLines Limited to develop and share (50/50) ownership of a LNG re-gasification facility at Gros-Cacouna, Quebec. Complementing the proposed LNG facility, Petro-Canada signed an MOU with OAO «Gazprom» (Gazprom) to investigate a joint project to ship LNG from Russia to North American markets by 2009. With an international presence and extensive marketing experience, Petro-Canada is well positioned to participate throughout the LNG value chain.

In addition to strategic initiatives, the Company also created shareholder value by returning funds to shareholders during the year. Commencing with the second quarter dividend paid on April 1, 2004, the Company increased the quarterly dividend 50% to $0.15 per share. Also, the Toronto Stock Exchange (TSX) approved Petro-Canada's application to make a normal course issuer bid for the repurchase of up to 21 million of its common shares over the 12-month period ending June 21, 2005, subject to certain conditions. By year-end 2004, the Company had repurchased and cancelled 6,868,082 shares at an average price of $65.02 per share for a total cost of approximately $447 million.

Other achievements during 2004 include improved operations from Oil Sands, with Syncrude reaching record production and MacKay River significantly improving reliability. In East Coast Oil, Hibernia maintained strong production during 2004, Terra Nova reached simple royalty payout and the White Rose development advanced on schedule and on budget. In Downstream, the Company successfully progressed the consolidation of its Eastern Canada refineries. This included the partial closure of the Oakville refinery, successful reversal and expansion of the Trans-Northern Pipelines Inc. (TNPI) pipeline, expansion of the Montreal refinery and the completion of logistics tie-ins to supply Ontario markets. Also in Refining and Supply, the Edmonton and Montreal refineries were successfully reconfigured to produce low-sulphur gasoline.

In September 2004, the Government of Canada completed the public offering of its remaining 19% interest in the Company. The government sold approximately 49 million Petro-Canada common shares at a price of $64.50 per share, resulting in total gross proceeds to the government of approximately $3.2 billion.

2003

In 2003, Petro-Canada achieved then record earnings from operations of $1.4 billion. In Oil Sands, a new strategy included a revised reconfiguration of the Edmonton refinery, a bitumen processing and refinery feedstock supply arrangement with Suncor Energy Inc. and a future focus on smaller scale bitumen projects similar to the MacKay River development. As a result, earlier plans for a large-scale bitumen plant at Meadow Creek were suspended. Internationally, Petro-Canada expanded its position in the U.K. sector of the North Sea through the exchange and acquisition of property interests. Two North Sea oil developments also came on-stream. Additionally, rights to new reserves were acquired in Syria and new exploration concessions were added to the portfolio in Tunisia, Algeria and Syria. In

Downstream, the Company moved ahead with plans to consolidate the Eastern Canada refining and supply operations. In Sales and Marketing, the program to convert selected Company-controlled retail sites to the new image standard surpassed the 80% completion mark. The proceeds from a $600 million US long-term fixed rate debt offering were applied to the reduction of a short-term floating rate acquisition facility. In addition to the proceeds of the fixed rate debt offering, net debt repayments of $548 million in 2003 re-established key financial ratios well within strategic targets.

2002

In 2002, earnings from operations were $1.0 billion. Petro-Canada acquired the majority of the upstream oil and gas businesses of Veba Oil & Gas GmbH (Veba) for $2,234 million, establishing International as a new core business. In Canada, strong operating performance at Hibernia combined with an exceptional start-up year at Terra Nova, raised Petro-Canada's share of East Coast crude oil production to 71,900 barrels per day (b/d). Development work commenced at White Rose, which will be the third producing oilfield on the Grand Banks. The MacKay River bitumen production facility was completed on schedule and on budget, and started production in November 2002. A natural gas discovery at the Tuk M-18 well in the Mackenzie Delta/Corridor region tested at restricted rates up to 30 million cubic feet per day (MMcf/d).

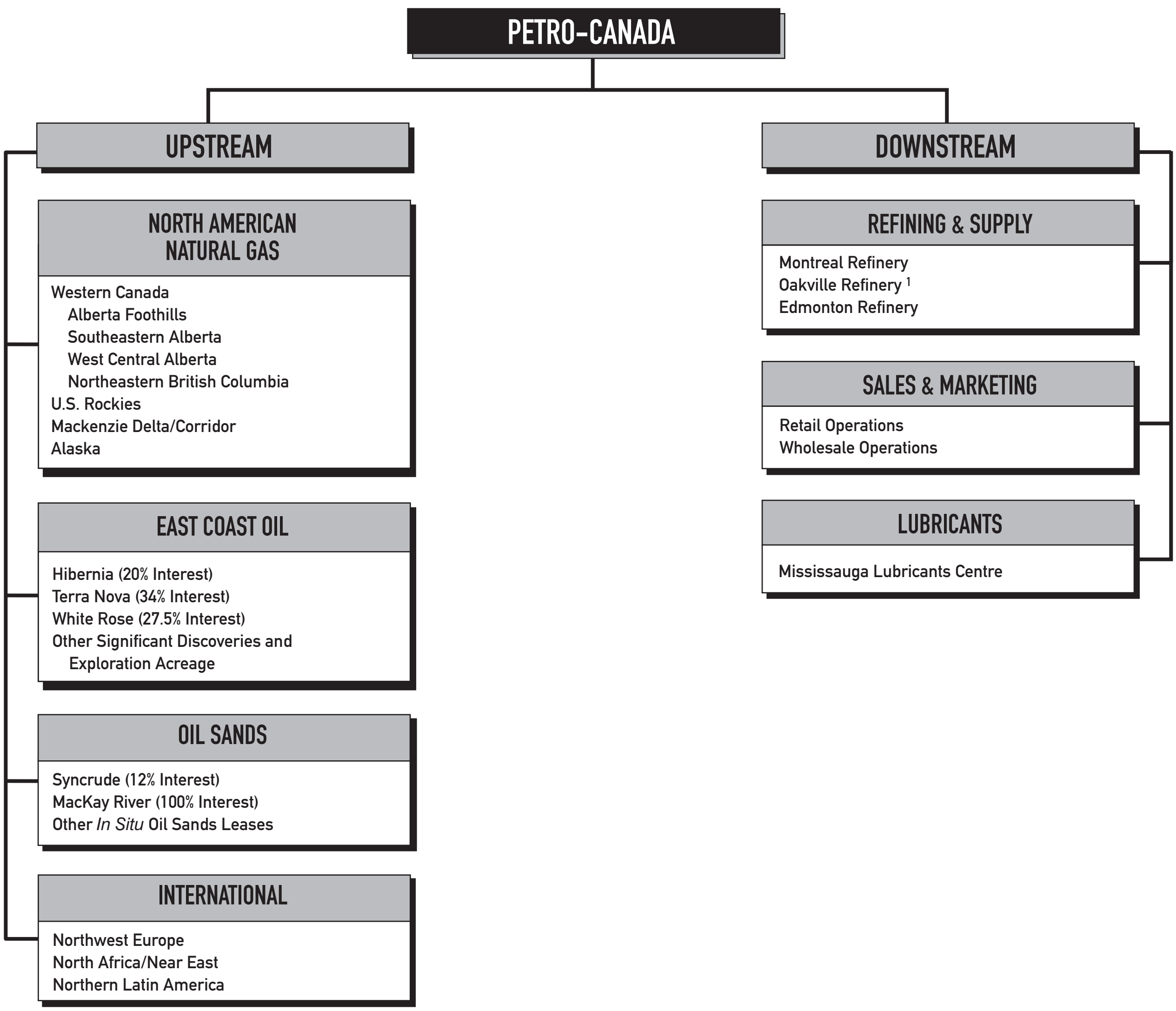
ITEM 5 – DESCRIPTION OF THE BUSINESS

Business of Petro-Canada

The following business description should be read in conjunction with Petro-Canada's Management's Discussion and Analysis (MD&A), as contained in the 2004 Annual Report, which is incorporated by reference into and forms an integral part of this AIF.

Petro-Canada is an integrated oil and gas company, a leader in the Canadian petroleum industry, with a portfolio of businesses spanning both the upstream and downstream sectors of the industry. In the upstream businesses, the Company explores for, develops, produces and markets crude oil, natural gas liquids (NGL) and natural gas in Canada and internationally. The Downstream business refines crude oil and other feedstocks, and markets and distributes petroleum products and related goods and services, primarily in Canada.

The chart below outlines the various businesses of Petro-Canada as at December 31, 2004.



[1] Petro-Canada's consolidation of Eastern Canada refinery operations includes the closure of the Oakville refinery in 2005.

Industry Conditions

Economic factors influencing Petro-Canada's upstream businesses financial performance include crude oil and natural gas prices and foreign exchange rates, particularly the Canadian dollar/U.S. dollar exchange rate. Prices for energy commodities are primarily affected by market supply and demand, weather and political events. Performance in Petro-Canada's Downstream business is influenced mainly by the level and volatility of crude oil prices, industry refining margins, movement in crude oil price differentials, demand for refined petroleum products and the degree of market competition.

Business Environment in 2004

The year 2004 was an extraordinary year in the history of energy commodity prices. International light crude oil prices, such as North Sea Brent (Brent) and West Texas Intermediate (WTI), reached average annual prices not seen since 1982. Light/heavy crude price differentials widened to unprecedented levels. North American natural gas prices attained their highest level since price deregulation in 1986.

The factors driving high oil prices were: a strong surge in global oil demand (led by China); slower growth in Russian production; continued interruption of Iraqi exports; and the impact of Hurricane Ivan on the U.S. Gulf of Mexico production. At the same time, increased production from the Organization of the Petroleum Exporting Countries (OPEC) and Mexico led to the supply of heavier grades of crude growing at a faster rate than the refining conversion capacity that was available for processing. The result was the widest light/heavy crude price differential on record.

Continued weakening of the U.S. dollar throughout 2004 resulted in the highest Canada/U.S. exchange rate in the past 10 years. The elevated exchange rate lowered the positive impact of higher international commodity prices. The Canadian dollar rose from 77.4 cents US on December 31, 2003, to 83.1 cents US on December 31, 2004, an increase of 7%.

North American natural gas prices enjoyed another year of buoyancy, despite record levels of storage gas due to weaker demand and better-than-anticipated production volumes. Concern regarding the underlying strength of production growth in North America and the impact of Hurricane Ivan on U.S. Gulf of Mexico production helped maintain Henry Hub monthly average gas prices at levels above $5.00 US per million British thermal units (MMBtu). Average Canadian natural gas prices mirrored the performance of prices south of the border, up from 2003 despite a substantial widening of the price differential between the Henry Hub and the AECO-C spot price.

In the Canadian downstream sector, refined petroleum product sales grew by about 4%, compared to 4.8% in 2003. Refining margins improved again in 2004, largely in response to bottlenecks in the North American refining system. The system continues to be stretched to its limit by a combination of growing refined product demand and increasingly stringent mandated product specifications. As well, record light/heavy crude price differentials contributed to margin improvements.

Risk Management

Petro-Canada's results are impacted by management's strategy for handling risks in the business. These risks fall into four broad categories: business risks; operational risks; political risks; and market risks.

Management believes each major risk requires a unique response based on Petro-Canada's business strategy and financial tolerance. While some risks can be effectively managed through internal controls and business processes, others are managed through insurance and hedging. The Audit, Finance and Risk Committee of the Board of Directors has responsibility to oversee risk management. The following describes Petro-Canada's approach to managing major risks.

Business Risks

Exploration

Petro-Canada's future cash flows are highly dependent on the ability to offset natural declines as reserves are produced. Reserves can be added through successful exploration or acquisitions; however, as basins mature, replacement of reserves becomes more challenging and expensive. In some areas, the Company may choose to allow reserves to decline if replacement is uneconomic. In 2004, the Company replaced 96% of its production on a proved reserves basis, compared to 59% in 2003. The Company targets to fully replace proved reserves over a five-year period. Petro-Canada's five-year proved reserves replacement ratio was 150%.[1]

There is no assurance Petro-Canada will successfully replace all produced reserves in any given year.

Reserves Estimates

Estimates of economically recoverable oil and gas reserves are based upon a number of variables and assumptions that include geoscientific interpretation, commodity prices, operating and capital costs, and historical production from properties.

Petro-Canada has well-established, corporate-wide reserves booking practices that have been continuously improved for more than a decade. PricewaterhouseCoopers LLP, as contract internal auditors, has tested the non-engineering management control process used in establishing reserves. As well, independent engineering firms assess a significant portion of the Company's reserves estimates every year. Over time, this means all of Petro-Canada's reserves estimates are assessed by external evaluators. The Board of Directors also reviews and approves the Company's annual reserves filings. More information on the Company's reserves booking practices can be found in the reserves section of this AIF.

Project Execution

Petro-Canada manages a number of different-sized projects to support continuing operations and future growth. Many projects are influenced by external factors beyond the Company's control. These include items such as material costs, labour productivity, timely availability of skilled labour and currency fluctuations.

While Petro-Canada cannot control all project inputs, the Company is committed to continuing to improve its project management capability. Petro-Canada's goal is to consistently and predictably deliver projects on time and on budget, and achieve defined expectations. Enhanced project management capability is expected to improve all elements of project execution including safety and environmental performance, quality, cycle-time and cost. Leveraging experience gained from major project developments, the Company has established project management best practices.

Non-Operated Interests

Other companies may manage the construction or operation of assets in which Petro-Canada has a significant interest. Business assets in which Petro-Canada has a major interest, but does not operate, include Hibernia (20% interest), Syncrude (12% interest), White Rose (27.5%) and the newly acquired Buzzard (29.9% interest). Major projects are managed through different forms of joint venture executive committees, resulting in Petro-Canada having some ability to influence these projects. As well, Petro-Canada has joint venture or other operating agreements which specify its expectations from third-party operators. Nevertheless, third-party operation and management of the Company's assets could adversely affect Petro-Canada's financial performance.

Environmental Regulations

Environmental risks in the oil and gas industry are significant. This is because related laws and regulations are becoming more stringent in Canada and in other countries where Petro-Canada operates. Due to increased regulations, Petro-Canada is investing additional capital to satisfy new product specifications and/or address environmental issues. In 2005, the Company will invest $635 million of its capital program toward regulatory compliance, most of which will be to modify refineries to produce low-sulphur distillate. Other environmental regulations may result in operating costs increasing in the future, as a result of creating a future liability when dismantling or remediating assets.

Petro-Canada conducts Life-Cycle Value Assessments (LCVA) to integrate and balance environmental, social and economic decisions related to major projects. A key component of the LCVA process is to assess and plan for all life-cycle stages involved in constructing, manufacturing, distributing and eventually abandoning an asset or a product. This process encourages more comprehensive exploration of alternatives. The LCVA is a useful technique; however, its predictive capability is limited by the reliance on the current regulatory regime or one that can be reasonably expected.

Emission of Greenhouse Gases

The Kyoto Protocol, ratified by the Government of Canada in December 2002 and effective as of February 16, 2005, requires signatory nations to reduce their emissions of carbon dioxide and other greenhouse gases. As a result, Petro-Canada may be required to reduce emissions of greenhouse gases from operations or purchase emission trading credits. While the details of implementation of the Kyoto

[1] Proved reserves replacement ratio is calculated by dividing the year-over-year net change in proved reserves before deducting production by the annual production during the year. The reserves replacement ratio is a general indicator of the Company's reserves growth. It is only one of a number of metrics which can be used to analyze a company's upstream business.

Protocol in Canada have not been finalized, the impact to Petro-Canada could be higher capital expenditures and operating expenses. The Government of Canada may also impose higher vehicle fuel efficiency standards. The impact of this action could be to decrease the demand for gasoline and diesel fuels sold by Petro-Canada and depress the Company's margins for refined products.

Petro-Canada is committed to reducing emissions. Additional detail on reducing emissions will be available in the Report to the Community in the second quarter of 2005. The Report will be available on the Company's Web site at www.petro-canada.ca. Through industry organizations, Petro-Canada continues to work with a number of regulatory groups and government associations to find a cost-effective approach which will minimize the negative financial impact of the Kyoto Protocol on the Company while still reducing emissions. The level of influence these discussions and cooperative efforts have on the Government of Canada's implementation plan may be quite limited.

Government Regulations

Petro-Canada's operations are regulated by, and could be intervened upon by, a variety of governments around the world. Governments could impact contracting of exploration and production interests, impose specific drilling obligations, and possibly expropriate or cancel contract rights. Governments may also regulate prices of commodities or refined products, or intervene through taxes, royalties and exploration rights.

Petro-Canada tries to mitigate the impact of government regulations by selecting operating environments with stable governments. To date, Petro-Canada has had a cooperative relationship with its regulators and the governments in the countries in which it operates. Most of the contact with regulators occurs through the Company's management, regulatory affairs personnel in each business unit and a centralized corporate government relations function. Petro-Canada aims to have regular, constructive communication with regulators and governments so issues can be resolved in a mutually acceptable fashion. The Company also has a strong record of regulatory compliance within the jurisdictions in which it operates. Petro-Canada operates in many different jurisdictions and derives revenue from several categories of products. This diversification makes financial performance less sensitive to the action of any single government. Nevertheless, Petro-Canada has limited ability to influence regulations which may have a material adverse effect on the Company.

Counterparties

In the normal course of business, Petro-Canada is exposed to credit risk resulting from the uncertainty of business partners' or counterparties' ability to fulfill their obligations. The Company has established internal credit policies and procedures that include financial assessments, exposure limits and processes to monitor and minimize the exposures against these limits. Where appropriate, Petro-Canada also uses netting and collateral arrangements to minimize risk.

Operational Risks

Exploring for, developing, producing, refining, transporting and marketing oil, natural gas and refined products involve significant operational hazards. These risks include well blowouts, fires, explosions, gaseous leaks, migration of harmful substances and oil spills. Any of these operational incidents could cause personal injury, environmental contamination, or damage and destruction of the Company's assets. These incidents could also interrupt production.

Petro-Canada manages operational risks primarily through a Total Loss Management (TLM) system and a corporate insurance program. TLM is an internally developed management system based on external best practices with standards for preventing operational incidents. Regular TLM audits test compliance with these standards. The corporate insurance program transfers the impact of some operational risks to third-party insurers worldwide. Petro-Canada optimizes the program by evaluating deductibles, limits and coverage. The Company's financial tolerance to withstand the impact of a major isolated event may be used to manage total premium cost. Although Petro-Canada maintains insurance in line with customary industry practices, the Company cannot fully insure against all risks. Losses resulting from operational incidents could have a material adverse impact on the Company.

Political Risks

Petro-Canada operates in a number of countries that have varying political, economic and social systems. As a result, the Company's operations and related assets are subject to potential risks from actions by governmental authorities or internal unrest. Petro-Canada also operates in OPEC-member countries and production in those countries is constrained by OPEC quotas.

The Company continually evaluates exposure in any one country in the context of total operations. Investment may be limited to avoid excessive exposure in any one country or region. The Company also uses financial products to partially mitigate some political risks.

Market Risks

More detailed quantification of the impact of some of the following risks can be found in the earnings sensitivity chart in the business environment section of the 2004 Annual Report.

Commodity Prices

In Petro-Canada's upstream businesses, a significant market risk exposure is the changing commodity prices of crude oil and natural gas. Commodity prices are volatile and influenced by factors such as supply and demand fundamentals, geopolitical events, OPEC decisions and weather. In 2004, the monthly average Brent crude oil price ranged between $30.83 US/bbl and $49.64 US/bbl, and the AECO-C hub index ranged between $5.93/Mcf and $8.35/Mcf. These commodity prices also impact the refined products margins realized by the Downstream business, another significant market risk. In 2004, the benchmark monthly average New York Harbor 3-2-1 refinery crack spread per bbl ranged from $4.23 US to $11.41 US. Petro-Canada's ability to maintain product margins in an environment of higher feedstock costs is contingent upon the Company's ability to flow higher costs through to customers.

Petro-Canada generally does not hedge large volumes of production. Management believes commodity prices are volatile and difficult to predict. The business is managed so that the Company can substantially withstand the impact of a lower price environment, while maintaining the opportunity to capture significant upside when the price environment is higher. However, commodity prices and margins may be hedged occasionally to capture opportunities that represent extraordinary value and to ensure the economic value of an acquisition. For example, as part of the Company's acquisition of an interest in the Buzzard field in the U.K. sector of the North Sea, the Company entered into a series of derivative contracts related to the future sale of Brent crude oil (see Derivative Instruments below). Certain Downstream physical transactions are routinely hedged for operational needs and to facilitate sales to customers.

Foreign Exchange

As energy commodity prices are primarily priced in U.S. dollars, a large portion of Petro-Canada's revenue stream is affected by the Canada/U.S. exchange rate. As a result, the Company's earnings are negatively affected by a strengthening Canadian dollar. The Company is also exposed to fluctuations in other foreign currencies, such as the euro and the British pound.

Generally, Petro-Canada does not hedge foreign exchange exposures, although the Company partially mitigates the U.S. dollar exposure by denominating the majority of its debt obligations in U.S. dollars. Foreign exchange exposure related to asset acquisitions or divestitures, or project capital expenditures, may be hedged on a case-by-case basis.

Interest Rates

Petro-Canada targets a blend of fixed and floating rate debt. Generally, this enables the Company to take advantage of lower interest rates on floating debt, while matching overall debt maturity with the life of cash-generating assets. The Company is exposed to fluctuations in the rate of interest it pays on floating rate debt.

This interest rate exposure is within the Company's risk tolerance.

Derivative Instruments

Petro-Canada's Market Risk and Derivative Policy prohibits the use of derivative instruments for speculative purposes. Petro-Canada uses derivatives primarily to hedge physical transactions for operational needs and to facilitate sales to customers. The gains and losses associated with these financial instruments essentially offset gains and losses on the physical transactions. Except as specifically authorized by the Board of Directors, the term of hedging instruments cannot exceed 18 months. Monitoring and reporting of the derivatives portfolio includes periodic testing of the fair value of all outstanding derivatives. Fair values are determined by obtaining independent third-party quotes for the value of each derivative instrument. The objectives and strategies of all hedge transactions are documented and the effectiveness of the derivative instrument in offsetting a change in the value of the hedged exposure is assessed on a regular basis.

Effective January 1, 2004, the Company elected to discontinue hedge accounting for certain hedging programs. All derivatives that do not qualify as a hedge, or are not designated as a hedge, are accounted for using the mark-to-market accounting method. These derivatives are recorded in the balance sheet as either an asset or liability, with the fair value recognized in earnings. As a result, the realized and unrealized values of these transactions are recognized in Investment and Other Income.

During 2004, as part of the Company's acquisition of an interest in the Buzzard field, the Company entered into a series of derivative contracts related to the future sale of Brent crude oil. The purpose of these transactions was to ensure value-adding returns to Petro-Canada on this investment, even in the event of a material decrease in oil prices. These contracts effectively lock in an average forward price of approximately $26 US/bbl on a volume of 35,840,000 barrels. This volume represents approximately 50% of the Company's share of estimated plateau production in the 2007 to 2010 time frame. As at December 31, this hedge had a mark-to-market unrealized loss of $205 million after tax which was recognized in net earnings in 2004.

In 2004, other commodity hedges in place for refining supply and product purchases resulted in a net decrease in earnings of about $1 million after-tax, which included a mark-to-market unrealized gain as at December 31 of $3 million after-tax. This compared with a net decrease in earnings of about $30 million in 2003, which related to commodity hedges, interest rate hedges and currency hedges.

Capital Expenditures on Property, Plant and Equipment and Exploration

The following table shows Petro-Canada's capital expenditures on property, plant and equipment and exploration for the years indicated.

CAPITAL EXPENDITURES ON PROPERTY, PLANT AND EQUIPMENT AND EXPLORATION
(millions of dollars)

	2004	2003	2002
Exploration			
North American Natural Gas	**$ 285**	$ 213	$ 259
East Coast Oil	**2**	47	26
Oil Sands	**16**	23	23
International			
Northwest Europe	**69**	43	33
North Africa/Near East	**53**	14	28
Northern Latin America	**3**	2	–
Total exploration	**428**	342	369
Development			
North American Natural Gas	**420**	314	250
East Coast Oil	**276**	297	264
Oil Sands	**383**	425	439
International			
Northwest Europe	**326**	254	60
North Africa/Near East	**133**	123	80
Northern Latin America	**22**	24	20
Total development	**1,560**	1,437	1,113
Property acquisitions			
North America Natural Gas	**19**	33	20
International			
Northwest Europe	**1,218**	65	–
Total property acquisitions	**1,237**	98	20
Downstream			
Refining and supply	**656**	296	210
Sales, marketing and other	**171**	117	118
Lubricants	**12**	11	16
Total Downstream	**839**	424	344
Shared Services	**9**	14	15
Total capital expenditures on property, plant and equipment and exploration	**$4,073** [1]	$2,315	$1,861

[1] Excludes U.S. Rockies acquisition of Prima Energy Corporation totaling $644 million, net of acquired cash.

Capital spending on property, plant and equipment and exploration in 2004 reflected Petro-Canada's commitment to long-term profitable growth and adding value for shareholders. The 76% increase in expenditures to $4,073 million, up from $2,315 in 2003, was mainly due to the Buzzard acquisition and costs associated with the development of the Buzzard project, the investments related to upgrading refineries to produce de-sulphurization of gasoline, increased spending for the pursuit of attractive opportunities in Western Canada and the acceleration of the Company's retail re-imaging program.

Planned investment for 2005, totaling $3,235 million, reflects a "building year" for Petro-Canada. The focus on growth initiatives will deliver new production in 2006 and 2007. The 2005 capital expenditure program will be funded from cash flow and existing credit facilities.

	2005 Capital Program	(millions of dollars)
I	Enhance existing assets	130
II	Regulatory compliance	635
III	Improve base business profitability	120
IV	Reserve replacement in core areas	950
V	New growth projects	1,130
VI	Exploration and new ventures	270
	Total 2005 capital program	**$3,235**

Note: Categories I to III are mainly associated with the Downstream business and Categories IV to VI are mainly associated with the upstream businesses.

Upstream

Petro-Canada's upstream operations consist of four business segments: North American Natural Gas, with current production in Western Canada and the U.S. Rockies; East Coast Oil, with three major developments offshore Newfoundland and Labrador; Oil Sands operations in Northeastern Alberta; and International, where the Company is active in three core areas: Northwest Europe, North Africa/Near East and Northern Latin America. This diverse asset base provides a balanced portfolio and a platform for long-term growth.

In both 2004 and 2003, 100% of the revenues from sales of crude oil, NGL, bitumen, synthetic crude oil and natural gas came from sales to third parties and intersegment sales. There are no revenues derived from sales to investees and sales or transfers to controlling shareholders.

North American Natural Gas

Business Summary and Strategy

North American Natural Gas has a long history of exploring for and producing natural gas, crude oil and NGL in Western Canada. This business also markets natural gas in North America, has established resources in the Mackenzie Delta/Corridor and has landholdings in Alaska. In 2004, the business expanded into unconventional production and signed an agreement to develop a proposed LNG re-gasification facility in Quebec.

The North American Natural Gas strategy is to be a significant and sustainable market participant by accessing new and diverse natural gas supply sources in North America. Key features of the strategy include:

- continuing exploration and development in existing Western Canada conventional areas;
- increasing focus on unconventional production in the U.S. Rockies and Western Canada;
- developing LNG import capacity in North America; and
- building a northern resource base for long-term growth.

Western Canada and U.S. Rockies

Western Canada continued to exploit conventional gas opportunities in four core areas: the Alberta Foothills, Northeastern British Columbia, Southeastern Alberta and West-Central Alberta. Western Canada natural gas production averaged 676 MMcf/d, down 2% from 693 MMcf/d in 2003. Exploration and development drilling activity in North American Natural Gas resulted in 675 gross (517 net) wells, including 642 gross (496 net) natural gas wells and seven gross (two net) oil wells, for an overall success rate of 96%.

North American Natural Gas reserves extensions, discoveries, revisions and improved recovery added 147 billion cubic feet (Bcf) of natural gas and 2.1 MMbbls of crude oil and NGL to proved reserves before royalties. Property acquisitions added 116 Bcf of natural gas and 5.7 MMbbls of crude oil and NGL to proved reserves. Sales of producing properties with reserves totaling one Bcf of natural gas were completed during the year. Annual production before royalties totaled 254 Bcf of natural gas and 5.6 MMbbls of conventional crude oil and NGL.

During 2004, the North American Natural Gas business grew to include unconventional gas operations and skills. In mid-2004, its footprint was extended into the U.S. Rockies with the acquisition of Prima Energy Corporation (U.S. Rockies) for $644 million, net of acquired cash. This acquisition added 55 MMcfe/d from coal bed methane in the Powder River Basin and from tight gas in the Denver-Julesburg Basin, and significant expertise in unconventional production. The value from the U.S. Rockies acquisition will come from developing the large inventory of probable reserves. The Company plans to double unconventional gas equivalent production to 100 MMcfe/d by 2007.

The royalty regime is a significant factor in the profitability of crude oil and natural gas production. Royalties on conventional crude oil and natural gas owned by provincial governments are determined by regulation and may be amended from time to time. Royalty payments to provincial governments are generally calculated as a percentage of production and vary depending upon factors such as well production volumes, selling prices, method of recovery, location of production and date of discovery. Royalties payable on production of privately owned crude oil and natural gas are negotiated with the mineral rights owner. In 2004, Petro-Canada's average royalty rate for North American Natural Gas was approximately 24% for conventional crude oil, NGL and natural gas.

Within Western Canada, Petro-Canada operates 11 natural gas field processing plants with total licensed capacity of approximately 1.1 Bcf/d, of which the Company's share is approximately 691 MMcf/d. The following table shows Petro-Canada's ownership and capacity of operated processing plants.

PETRO-CANADA OWNERSHIP AND CAPACITY

Petro-Canada Operated Plants	Working Interest Ownership (%)	Gross Licensed Capacity (MMcf/d)	Net Licensed Capacity (MMcf/d)
Brazeau Sweet	47	78	37
Brazeau Sour	30	107	32
		185	69
Hanlan Sweet	41	44	18
Hanlan Sour	46	380	175
		424	193
Wildcat Hills	66	124	82
Bearberry	100	94	94
Ferrier	99	119	119
Gilby East	100	52	52
Wilson Creek Sweet	52	13	7
Wilson Creek Sour	52	22	11
		35	18
Boundary Lake Sweet	100	20	20
Boundary Lake Sour	50	66	33
Parkland 1	44	18	8
Parkland 2	35	10	3
Total 2004		**1,147**	**691**

Petro-Canada also has varying working interests in other natural gas processing plants and field gathering facilities operated by other oil and gas companies. The Company's share is approximately 277 MMcf/d of licensed capacity.

In 2004, North American Natural Gas marketed 862 MMcf/d of natural gas. U.S. Rockies sales from July 29, 2004 to December 31, 2004, were 43 MMcf/d, of which 10 MMcf/d were direct sales. In Western Canada, the Company markets natural gas produced by other companies in addition to Petro-Canada's own production. In Western Canada, the Company sold 844 MMcf/d, down from 850 MMcf/d in 2003. To achieve better control over sales volumes, prices and transportation-related costs, Petro-Canada focuses on direct sales to end users, distribution companies, wholesale marketers and natural gas spot markets. Marketing efforts include management of the gas portfolio, gas supply, pipeline commitments and customer relationships.

The following table shows the market distribution of Petro-Canada's Western Canada natural gas sales.

WESTERN CANADA NATURAL GAS SALES BY MARKET

	2004		2003	
	(MMcf/d)	**(% of Total)**	(MMcf/d)	(% of Total)
Sales to aggregators				
Canwest Gas Supply Inc.	**16**	**2**	32	4
ProGas Limited	**35**	**4**	38	5
Cargill Incorporated	**17**	**2**	21	2
Others	**6**	**1**	4	1
Total sales to aggregators	**74**	**9**	95	12
Direct sales				
Alberta	**368**	**43**	351	41
U.S. Midwest	**159**	**19**	162	19
British Columbia and U.S. Pacific Northwest	**106**	**13**	78	9
California	**45**	**5**	45	5
Eastern Canada	**12**	**1**	43	5
Saskatchewan	**8**	**1**	8	1
Total before internal sales	**698**	**82**	687	80
Sales within Petro-Canada	**72**	**9**	68	8
Total direct sales	**770**	**91**	755	88
Total sales	**844**	**100**	850	100
Total direct sales exports	**204**	**24**	207	24

The Company has future commitments to sell and transport natural gas associated with normal operations. Under future fixed-price commitments entered into during the 1990s, approximately 10 MMcf/d (1.6% of estimated 2005 natural gas production in Western Canada) has been sold at an average plant gate netback price of $3.17/Mcf. In 2006, the volume of natural gas sold under these fixed-price contracts will remain at 10 MMcf/d at a price of $3.29/Mcf.

Mackenzie Delta/Corridor, Northwest Territories

With interests in six blocks, covering approximately one million gross undeveloped acres (0.6 million net acres), Petro-Canada is a significant leaseholder in the Mackenzie Delta/Corridor. Petro-Canada's holdings are comprised of four exploration licences and two Inuvialuit land concessions. Petro-Canada is the operator of the four licences. The Company's net work commitments on the four licences total approximately $140 million over five years and are guaranteed by performance bonds totaling approximately $35 million. Work to date has reduced the outstanding bond obligation to $18 million. Work commitments on the Inuvialuit land concessions include seismic acquisition and drilling a total of three wells. In 2002, a natural gas discovery at the Tuk M-18 well tested at restricted rates up to 30 MMcf/d. This has allowed Petro-Canada to make a non-binding nomination of 30 MMcf/d to support the development proposal for the Mackenzie Valley Pipeline. Having secured the area's most prospective acreage for future exploration, Petro-Canada will pace activities pending the approval/construction timeline of the Mackenzie pipeline.

Petro-Canada also holds a significant position in the Colville Hills area of the Mackenzie Corridor where the Company holds a 100% interest in two Significant Discovery Areas (SDAs) and one exploration licence.

Alaska

Petro-Canada's focus in Alaska is in the Foothills area north of the Brooks Mountain Range. A field geological study has confirmed that the geology and prospectivity of this area is similar to the Alberta Foothills, where Petro-Canada has developed considerable expertise and has had significant success finding natural gas. In addition, a large land position was acquired in the National Petroleum Reserve – Alaska, an area with significant potential for large oil prospects. The Company's Alaskan landholdings at year-end 2004 totaled 753,000 acres (gross and net). While it is unlikely the region will be serviced by a pipeline for some time, Petro-Canada's acreage is close to a proposed pipeline route to southern markets.

Liquefied Natural Gas (LNG)

Petro-Canada is seeking to participate in the global LNG business consistent with its strategy to add long-life producing assets to its portfolio. In September 2004, a MOU was signed with TransCanada PipeLines Limited to develop and share (50/50) ownership of a $660 million LNG facility at Gros-Cacouna, Quebec. The proposed facility, targeted to be in-service by late 2009, will receive, store and re-gasify imported LNG. Petro-Canada would own and market 100% of the send-out capacity of approximately 500 MMcf of natural gas per day.

East Coast Oil

Business Summary and Strategy

Petro-Canada is positioned in every major oil development off Canada's East Coast. The Company is the operator and holds the largest interest in Terra Nova (34%), and has a 20% interest in Hibernia, the first Grand Banks development. Petro-Canada also holds a 27.5% interest in the White Rose project, scheduled to be on-stream in 2006.

The East Coast Oil strategy is to improve reliability and sustain profitable production well into the next decade. Key features of the strategy include:

- delivering top quartile safety and operating performance;
- sustaining profitable production through reservoir extensions and add-ons; and
- pursuing high potential development projects.

Hibernia

The Hibernia oilfield lies approximately 315 kilometres east-southeast of St. John's, Newfoundland and Labrador. The Hibernia field, encompassing the Hibernia and Ben Nevis Avalon reservoirs, is estimated to have a remaining production life of 15 to 16 years. Assessment continues of the development potential of the Ben Nevis Avalon.

At December 31, 2004, there were 26 producing oil wells, 13 water injection wells and six gas injection wells in operation. Field production is transported by shuttle tanker either from the platform to a trans-shipment terminal on the Avalon Peninsula or, if tanker schedules permit, directly to market. Crude oil delivered to the trans-shipment facility is transferred to storage tanks and loaded onto tankers for transport to markets in Eastern Canada and the U.S. Petro-Canada has a 14% ownership interest in the trans-shipment facility.

Petro-Canada's share of Hibernia's production averaged 40,800 b/d in 2004, up from 40,600 b/d in 2003. The Hibernia platform continued to deliver first quartile operating performance. As a result of better-than-expected reservoir performance and development drilling in 2004, the life of field reserves estimate at Hibernia increased from 835 MMbbls at year-end 2003 to 940 MMbbls at year-end 2004. Petro-Canada's share of these reserves is 20%.

Terra Nova

The Terra Nova oilfield, which lies approximately 350 kilometres east-southeast of St. John's, Newfoundland and Labrador, was discovered by Petro-Canada in 1984. The Terra Nova field is estimated to have a remaining production life of approximately 12 to 14 years.

At year-end 2004, 12 producing oil wells, five water injection wells and three gas injection wells were in operation. Terra Nova utilizes the same system of shuttle tankers and a trans-shipment terminal that is currently used for Hibernia, and also transports its crude oil to markets in Eastern Canada and the U.S.

The Company's share of production averaged 37,400 b/d in 2004, down from 45,500 b/d in 2003. Both production and reliability measures were significantly below target due to extended maintenance activities and operating difficulties in the third and fourth quarters of 2004. During the third quarter, volumes were impacted by a longer-than-expected turnaround for repairs to the gas compression facilities. Further downtime occurred in the fourth quarter for investigation and repairs following a discharge of oily water. Following successful maintenance activities, production rates were ramped up to normal levels during the last half of December.

White Rose

Petro-Canada has a 27.5% working interest in the White Rose project, a $2.3 billion offshore development. Design capacity is 100,000 b/d, with an anticipated plateau production rate of 90,000 b/d. In 2004, key project milestones included: arrival of the Sea Rose Floating Production, Storage and Offleading (FPSO) hull in Newfoundland and Labrador; fabrication and lifting of the topsides modules onto the hull of the FPSO; initiation of the marine construction program offshore; and drilling of the first five development wells with pre-commissioning activities under way. The project remained on budget and on schedule in 2004, with first oil projected in early 2006.

Development plans for White Rose include the drilling of 19 to 21 wells to recover an estimated 200 MMbbls to 250 MMbbls of oil over a 10- to 12-year time frame. Ten wells, five producing wells, four water injection wells and one gas injection well will be drilled prior to production start-up.

Chartered tankers will transport White Rose production directly to markets in Eastern Canada and the U.S.

Offshore Oil Royalty Regime

In July 2003, the Government of Newfoundland and Labrador promulgated regulations for the royalty regime that will apply to the development of petroleum resources in offshore areas other than Hibernia and Terra Nova. The generic offshore royalty regime consists of a sliding-scale basic royalty payable throughout a project's life, and a two-tier net royalty payable upon the achievement of specified levels of profitability. The basic royalty is calculated as a percentage of gross field revenue commencing at 1% and rising to 7.5%, depending on cumulative production levels and the achievement of simple payout. Upon reaching tier one payout, including a return allowance, the net royalty is calculated as the greater of the basic royalty, or 20% of net revenue. An additional 10% net royalty rate is payable once a higher level of return on investment is attained. The generic royalty will apply to the White Rose development.

The royalty regime for the Hibernia project has three tiers: gross royalty, net royalty and supplementary royalty. Gross royalty increased to 5% of gross field revenue on July 1, 2003. The gross royalty rate will remain at 5% until net royalty payout is reached. The gross royalty is indexed to crude oil prices under certain conditions. Upon achieving payout, including a specified return allowance, the net royalty payable becomes the greater of 30% of net revenue or 5% of gross revenue. After a further level of payout is reached, which includes an additional return allowance, a supplementary royalty of 12.5% of net revenue also becomes payable.

The Terra Nova royalty regime has three tiers. The royalty consists of a sliding-scale basic royalty payable throughout the project's life, with two additional tiers of net royalties payable upon the achievement of specified levels of profitability. The basic royalty is payable as a percentage of gross field revenue, with an initial rate of 1%, which rises to 10% depending on cumulative production levels and the occurrence of simple payout. After tier one payout, including a specified return allowance, has been reached, net royalty will become the greater of the basic royalty or 30% of net revenue. An additional net royalty equal to 12.5% of net revenue will be payable once a further level of payout, including an additional return allowance, is attained. Terra Nova royalty rates increased to 5% in mid-2004 due to achieving simple payout for royalty purposes. Further increases in royalty will occur in line with the project's profitability-sensitive royalty regime. Terra Nova royalties are forecast to average approximately 12% in 2005.

Other Offshore Exploration and Development

In addition to current East Coast Oil developments, Petro-Canada holds interests in a number of discoveries, including the Hebron/Ben Nevis oilfield discoveries where the Company's interest is 23.9%. Petro-Canada plans to continue development drilling in the main fields, to bring on the Far East block at Terra Nova and to expand the development of the Ben Nevis Avalon reservoir at Hibernia. Production from these extensions will partially offset the declines in the main reservoirs at Hibernia and Terra Nova.

Oil Sands

Business Summary and Strategy

Petro-Canada's major Oil Sands interests include a 12% ownership in the Syncrude joint venture (an oil sands mining operation and upgrading facility), 100% ownership of the MacKay River *in situ* bitumen development (a steam-assisted gravity drainage (SAGD) operation), a 60% ownership in and operator of the Fort Hills oil sands mining project, and extensive oil sands acreage holdings considered prospective for *in situ* development of bitumen resources.

The Oil Sands strategy for profitable growth includes:

- phased and integrated development of reserves to incorporate knowledge gained;
- disciplined capital investment to ensure long-life projects are value creating; and
- a staged approach to development of capital-intensive Oil Sands projects to allow rigorous cost management and the opportunity to benefit from evolving technology.

Oil Sands Mining – Syncrude

Petro-Canada has a 12% interest in Syncrude, the world's largest oil sands mining operation. Located north of Fort McMurray, Alberta, Syncrude is a joint venture formed to mine shallow deposits of oil sands, and to extract and upgrade bitumen to produce synthetic crude oil. Syncrude holds eight oil sands leases issued by the Province of Alberta, covering approximately 255,000 acres. Syncrude has an estimated remaining reserve life in excess of 35 years. Three mines are currently in operation at Syncrude: the Base mine where operations are carried out using drag lines, bucket wheel reclaimers and belt conveyors; and the North mine and Aurora mine, where truck, shovel and hydro-transport systems are in use. An extraction process recovers about 90% of the crude bitumen contained in the mined sands. Refining processes upgrade the bitumen into high-quality, light (32 degree API) sweet synthetic crude oil. Syncrude's synthetic crude oil production is processed at refineries in Edmonton, Alberta, Eastern Canada and the U.S. At Syncrude, the priorities have been to improve reliability and lower unit operating costs.

In 2004, Syncrude attained record gross production of 238,000 b/d. Syncrude also lowered unit operating costs to $21.13/bbl, compared with $23.64/bbl in 2003, due to improved reliability and higher volumes.

In 1997, the Syncrude owners approved a staged growth strategy for the next decade. The Stage III expansion will add a second Aurora mine and an upgrading expansion. Construction progress and costs remain in line with the revised plan announced in March 2004 and completion is scheduled mid-2006. Following completion of the Stage III expansion, Petro-Canada expects its share of production capacity to grow to approximately 42,000 b/d. Production will reach this level following a ramp up period of two to three years.

Oil Sands In Situ – Bitumen

In September 2002, Petro-Canada successfully completed construction of its 100% owned, *in situ* bitumen production facility at MacKay River. Following the introduction of steam to the reservoir, Petro-Canada commenced bitumen production in November 2002. The extraction process at MacKay River utilizes SAGD, a technology that Petro-Canada participated in developing through its involvement in the Underground Test Facility (UTF). SAGD combines horizontal drilling with thermal steam injection. Steam is injected into the reservoir through the top well of a horizontal well pair to mobilize the bitumen, which flows to the lower producing well. This technology can economically recover more than 60% of the bitumen in place. The initial development at MacKay River includes two well pads of 12 and 13 horizontal well pairs. Well pairs are about 700 to 750 metres in length and are expected to produce about 1,200 b/d of bitumen. On average, wells are expected to have a six- to eight-year life. More than 90% of the water used to generate steam at MacKay River is recycled, a key feature of the environmental efficiency of the facility. The bitumen production from the project is currently being transported to the Athabasca Pipeline Terminal via a lateral insulated pipeline operated by Enbridge Pipelines (Athabasca) Inc. To enable onward shipment through major North American pipelines, the bitumen is diluted with synthetic crude oil, provided under a long-term supply arrangement with Suncor Energy Marketing Inc. The MacKay River reserves are expected to sustain plateau production of 25,000 b/d to 30,000 b/d, after accounting for well maturity, turnarounds and unplanned events, for approximately 25 to 30 years.

During 2004, MacKay River improved reliability of operations and production, but fell short of full year expectations of 25,000 b/d. MacKay River production for the year averaged 16,600 b/d, compared to 10,700 b/d in 2003. Production was impacted by a one-week outage and subsequent ramp up resulting from a mechanical problem with the plant. There were also steam limitations when the co-generation facility was not operational due to water treatment reliability. Reliability improved with steady operations from the 165-megawatt co-generation facility (owned by TransCanada Energy Ltd.) for the second half of 2004. Equipment to improve water treatment and plant reliability was successfully tied-in during the planned turnaround in the third quarter.

In 2005, Petro-Canada plans to add a third well pad at MacKay River to increase reservoir production and maximize plant throughput. New well pads will be built and drilling will continue as necessary throughout the life of the field. Through these improvements, Petro-Canada is gaining experience and knowledge to incorporate in the Company's next *in situ* projects.

Winter drilling programs are focused on the potential expansion at MacKay River and evaluation of other oil sands leases. Petro-Canada expects its next *in situ* project to come on-stream by the end of this decade.

Royalty Regime

The MacKay River operation is subject to the 1997 Alberta Oil Sands Royalty Regulation. Prior to royalty payout, which includes a specified return allowance, the royalty is calculated as 1% of gross revenue. After royalty payout, the royalty is based on the greater of 1% of gross revenue or 25% of net revenue. The net revenue is determined by subtracting allowed operating and capital costs from gross revenue. In 2004, the royalty paid was $0.16/bbl.

During 2001, Syncrude completed the transition from a project-specific contractual royalty to the 1997 Province of Alberta Oil Sands Royalty Regulation. Effective January 2002, the royalty payable by Syncrude to the Province of Alberta was set at the greater of 1% of gross revenue or 25% of net revenue. The net revenue is determined by subtracting allowed operating and capital costs from gross revenue. In 2004, the royalty paid averaged $0.61/bbl. If synthetic oil prices stay at current levels, the Company anticipates Syncrude will reach royalty payout sometime in 2006, at which time royalty rates will increase to 25% of net revenue.

Integrated Oil Sands Development

At the Edmonton refinery, Petro-Canada is investing to convert the facility to exclusively oil sands feedstocks and to produce low-sulphur products. By mid-2008, capital investment of $1.2 billion will expand coker capacity, add new crude and vacuum units, increase sulphur plants and expand utilities. This will enable Petro-Canada to directly upgrade 26,000 b/d of bitumen and process 48,000 b/d of sour synthetic crude oil, replacing the conventional light crude feedstock refined today. The refinery conversion program supports the long-term strategy and builds on the current $1.4 billion investment in gasoline and diesel desulphurization.

Fort Hills Acquisition

In early 2005, Petro-Canada strengthened its position in mining by becoming a 60% interest holder and operator of the Fort Hills oil sands mining project. The Company plans to develop this estimated 2.8 billion bbls of bitumen resource (1.7 billion bbls net to Petro-Canada) over a 30- to 40-year period.

International

Business Summary and Strategy

The Company's International production and exploration interests are currently focused in three regions. In Northwest Europe, production comes from the U.K. and The Netherlands sectors of the North Sea. The North Africa/Near East region provides the major portion of International crude oil production from interests principally in Syria and Libya. In Northern Latin America, operations are focused in Trinidad and Venezuela.

The International business is the platform for Petro-Canada's global growth. The strategy is to access a sizeable international resource base using a three-fold approach to:

- expand and exploit the existing portfolio of assets;
- target new opportunities and acquisitions with a focus on long-life assets; and
- build a balanced exploration program to replace reserves over time.

Northwest Europe

Production in Northwest Europe comes from the U.K. and The Netherlands sectors of the North Sea, with exploration programs extending into Denmark and the Faroe Islands. Extensive industry development has taken place in the North Sea since the early 1970s. While the basin is now a mature play, moderate-size fields continue to be developed and exploited.

Petro-Canada's strategy is infrastructure-centred with a focus on expanding the present portfolio. In Danish waters, the Company holds interests in three non-operated licences. In the Faroe Islands area, Petro-Canada has an interest in one non-operated licence. In the U.K. sector, Petro-Canada's interests are focused in three core areas: around the Scott field, the Triton FPSO and the Buzzard development.

In the Outer Moray Firth, Petro-Canada holds a 20.6% working interest in the Scott oilfield and production platform, and a 9.4% working interest in the Telford oilfield, a subsea tieback to the Scott platform. High-quality crude oil from Scott and Telford is transported to shore via the Forties Pipeline System. Associated gas is transported via the Scottish Area Gas Evacuation pipeline system.

In the Central North Sea, the Company's interests are centered on the Triton development area, which comprises the joint development of the Guillemot West and Northwest fields, the Bittern field and the Clapham field, which came on-stream at the end of 2003. The Pict field, currently under development and due on-stream in mid-2005, will be subsea and will produce through the Triton FPSO. The crude oil gathered at Triton is shipped via tanker, while gas is exported through the SEGAL system to the U.K. Petro-Canada is a 33.1% owner of the Triton FPSO. At year-end 2004, Petro-Canada was drilling an exploration prospect in the Triton development area.

In June 2004, the third U.K. area of focus was added in Outer Moray Firth through the acquisition of a 29.9% interest in the Buzzard oilfield. The purchase also included nearby blocks that have exploration potential. The Buzzard field is currently under development and first oil is expected in late 2006. Peak production of 60,000 boe/d net to Petro-Canada is expected in late 2007. The field is being developed with three bridge-linked platforms supporting the wellhead facilities, the production facilities, and living quarters and the utilities. The current base development anticipates that the field will be produced through 27 production wells, eight of which will be pre-drilled and available for production start-up. In a separate transaction, Petro-Canada farmed-into as operator an exploration licence approximately 40 kilometres northwest of Buzzard. An exploration well will be drilled on this block in the first quarter of 2005.

In The Netherlands sector, the major source of gas production is from Blocks L8b and L5c (Petro-Canada working interests – 25% and 30%, respectively). The produced gas is transported to shore by pipeline and sold to NV Nederlandse Gasunie under long-term delivery/offtake contracts. Petro-Canada's oil production from The Netherlands sector is primarily from the Petro-Canada operated Hanze field (Petro-Canada working interest – 45%). Oil from the Hanze platform is exported by dedicated tanker, with the cargoes marketed on a spot basis into Northwest Europe. Petro-Canada also holds a 12% interest in the onshore Bergen gas storage facility operated by BP p.l.c.

During 2004, a new oil development project, De Ruyter, advanced with the major contracts let by year end. The field, located in the Southern North Sea, approximately 60 kilometres northwest of The Hague, will be developed using a gravity base structure platform similar to the Hanze development. Peak production of 10,000 b/d net to Petro-Canada is expected to be on-stream in late 2006. Crude oil will be exported to shore via shuttle tanker. Gas export will be via tie-in to an existing pipeline.

North Africa/Near East

The core region of North Africa/Near East provides a substantial portion of Petro-Canada's International production.

In Syria, Petro-Canada's producing interests are consolidated under production-sharing contracts (PSCs) with Syria Shell Petroleum Development B.V. and the Syrian Petroleum Company. This joint venture, under the name Al Furat Petroleum Company (AFPC), produces about 50% of Syrian production. AFPC produces oil and natural gas from more than 30 fields in three concession areas. Petro-Canada's working interests range from 33% to 37.5% in each of these fields. AFPC's near-term goal is to minimize the rate of production decline and maximize recovery from these mature fields. In mid-2003, Petro-Canada, together with Syria Shell Petroleum Development B.V., finalized an agreement with the Syrian government that extended rights to deep and lateral reserves on the existing acreage. The agreement supplements the three existing PSCs. Oil produced by the joint venture is exported via the Syrian Company for Oil Transport pipeline to the coastal Banias terminal. The natural gas production is sold into the Syrian domestic system.

In 2003, Petro-Canada signed a PSC for exploration of Block II with the Syrian government and the Syrian Petroleum Company. Petro-Canada holds a 100% interest as operator of the PSC. The work program includes reprocessing of existing, and acquisition of new, seismic data, and the drilling of two exploration wells. The Block is located in Northeast Syria and is within workable distance of existing infrastructure. In 2004, Petro-Canada undertook an extensive data gathering project on the Block in preparation for shooting both 2D and 3D seismic in 2005.

In Libya, Petro-Canada is one of the country's largest producers through its 49% interest in Veba Oil Operations (VOO), a joint venture with the National Oil Corporation of Libya (NOC). Most of Libya's production is high-quality, low-sulphur (sweet) crude oil. As Libya is a member of the OPEC, Libyan production may be constrained by OPEC quotas.

Petro-Canada's production through the VOO joint venture comes from three concessions that combine the operations of more than 20 fields, and one exploration and production sharing-agreement (EPSA) covering the En Naga North and En Naga West oilfields. Petro-Canada also has equity interests in the Ras Lanuf export terminal and various pipelines, through which the majority of the production is exported. Petro-Canada's production is currently sold on contract to the NOC.

In Algeria, Petro-Canada was successful in its bid for the Zotti Block offered in the Algerian fourth licensing round. Petro-Canada, with a 100% working interest, is operator. The award received final government approval late in 2004 and preparations are ongoing for shooting 2D seismic and drilling one well during 2005.

With an effective date of December 31, 2004, Petro-Canada relinquished its Tinrhert Block PSC with SONATRACH, the Algerian national oil company. This included a 70% interest in the Tamadanet oilfield, which was producing about 600 b/d at the end of the year. The final terms of the settlement will be agreed upon in the first part of 2005.

In Tunisia, Petro-Canada is operator and has a 72.5% interest in the Melitta Block, located mainly offshore in the Mediterranean Sea. Following official gazetting by the authorities in late 2004, Petro-Canada is preparing to drill the first of two exploration wells. At year-end 2004, Petro-Canada relinquished the Tatouine Block exploration permit in south central Tunisia.

In February 2004, the Company completed the sale of a non-core asset, a 40% interest in the Temir licence in Kazakhstan (including the Saigak oilfield).

Northern Latin America

In Northern Latin America, Petro-Canada's operations are focused in Trinidad where the Company holds a 17% working interest in the North Coast Marine Area 1 (NCMA-1) offshore gas project operated by BG Group plc (British Gas). The PSC covers the ongoing development of three gas fields – Hibiscus, Poinsettia and Chaconia. Initial field development, including commissioning of the Hibiscus production platform, was completed in August 2002 with natural gas production coming on-stream in the third quarter of 2002. Production is delivered by pipeline to the LNG facility operated by Atlantic LNG at Point Fortin for liquefaction and subsequent sale into U.S. markets.

In Western Venezuela, Petro-Canada holds a 50% working interest in the La Ceiba Block that straddles the eastern shores of Lake Maracaibo. In 2003, Petroleos de Venezuela, S.A., the national oil company of Venezuela, approved an agreement for an extended production test to evaluate the commercial viability of the La Ceiba oil discovery. The extended production test of the La Ceiba development began operations during the fourth quarter of 2004. Upon completion of the three-month test program, the results will be evaluated for commercial viability.

Upstream Production and Prices

The following table shows Petro-Canada's average daily production of conventional crude oil, NGL, bitumen, synthetic crude oil (from mining operations) and natural gas, before and after deduction of royalties for the years indicated.

AVERAGE DAILY PRODUCTION OF CRUDE OIL, NATURAL GAS LIQUIDS, BITUMEN, SYNTHETIC CRUDE OIL AND NATURAL GAS

	Years Ended December 31,					
	2004		2003		2002 [1]	
	Before Royalties	**After Royalties**	Before Royalties	After Royalties	Before Royalties	After Royalties
Crude oil and equivalents (Mbbl/d)						
East Coast Oil	**78.2**	**75.1**	86.1	84.0	71.9	70.9
Oil Sands [2]	**45.2**	**44.8**	36.1	35.7	28.6	28.2
North American Natural Gas	**15.3**	**11.4**	16.9	12.6	18.9	14.2
Northwest Europe	**40.4**	**40.4**	37.7	37.7	27.1	27.1
North Africa/Near East	**126.6**	**67.4**	143.1	77.9	98.4	48.1
Total crude oil and natural gas liquids	**305.7**	**239.1**	319.9	247.9	244.9	188.5
Natural gas production (MMcf/d)						
North American Natural Gas	**695**	**530**	693	521	722	557
Northwest Europe	**85**	**85**	80	80	60	60
North Africa/Near East	**21**	**3**	32	6	30	8
Northern Latin America	**72**	**51**	63	63	13	13
Total natural gas	**873**	**669**	868	670	825	638
Total production [3] (Mboe/d)	**451**	**351**	465	360	382	295
Proved oil and NGL reserves [4] (MMbbls)	**801**	**674**	796	650	830	657
Proved natural gas reserves (trillions of cubic feet – Tcf)	**2.5**	**2.0**	2.5	2.0	2.8	2.1

1 Nearly all of 2002 International production was acquired effective May 2, 2002.
2 Includes production of synthetic crude oil from Syncrude mining operation.
3 Natural gas is converted to oil equivalent using 6,000 cubic feet of gas to one boe.
4 Includes reserves of synthetic crude oil from Syncrude mining operation.

The following table shows Petro-Canada's average daily production of conventional crude oil, NGL, bitumen, synthetic crude oil and natural gas, before deduction of royalties by quarter for the years indicated.

AVERAGE DAILY PRODUCTION OF CRUDE OIL, NATURAL GAS LIQUIDS, BITUMEN, SYNTHETIC CRUDE OIL AND NATURAL GAS BEFORE ROYALTIES BY QUARTER

	2004 Three Months Ended				2003 Three Months Ended			
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	Mar. 31	June 30	Sept. 30	Dec. 31
Crude oil and equivalents (Mbbl/d)								
East Coast Oil	**87.5**	**85.4**	**71.5**	**68.4**	83.4	92.4	81.2	87.5
Oil Sands [1]	**47.4**	**40.7**	**45.4**	**47.1**	35.8	30.3	37.4	40.8
North American Natural Gas	**15.1**	**13.7**	**15.7**	**16.9**	18.8	17.2	15.8	15.6
Northwest Europe	**46.8**	**43.7**	**36.6**	**34.8**	42.3	39.9	30.0	38.9
North Africa/Near East	**135.1**	**127.1**	**122.8**	**121.5**	140.9	145.7	144.4	141.3
Total crude oil and equivalents	**331.9**	**310.6**	**292.0**	**288.7**	321.2	325.5	308.8	324.1
Natural gas (MMcf/d)								
North American Natural Gas	**677**	**691**	**690**	**720**	714	680	683	694
Northwest Europe	**104**	**85**	**79**	**74**	96	78	56	90
North Africa/Near East	**21**	**21**	**20**	**23**	33	35	33	28
Northern Latin America	**67**	**71**	**74**	**74**	49	62	69	74
Total natural gas	**869**	**868**	**863**	**891**	892	855	841	886
Total production [2] (Mboe/d)	**477**	**455**	**436**	**437**	470	468	449	472

1 Includes production of synthetic crude oil from Syncrude mining operation.

2 Natural gas is converted to oil equivalent using 6,000 cubic feet of gas to one boe.

The following table shows Petro-Canada's average daily production of conventional crude oil, NGL, bitumen, synthetic crude oil and natural gas, after deduction of royalties by quarter for the years indicated.

AVERAGE DAILY PRODUCTION OF CRUDE OIL, NATURAL GAS LIQUIDS, BITUMEN, SYNTHETIC CRUDE OIL AND NATURAL GAS AFTER ROYALTIES BY QUARTER

	2004				2003			
	Three Months Ended				Three Months Ended			
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	Mar. 31	June 30	Sept. 30	Dec. 31
Crude oil and equivalents (Mbbl/d)								
East Coast Oil	**85.0**	**82.4**	**68.2**	**65.2**	81.6	90.7	78.7	85.2
Oil Sands [1]	**47.0**	**40.3**	**45.0**	**46.5**	35.5	30.0	36.9	40.5
North American Natural Gas	**11.1**	**10.1**	**11.6**	**12.6**	14.7	12.5	11.8	11.2
Northwest Europe	**46.8**	**43.7**	**36.6**	**34.8**	42.3	39.9	30.0	38.9
North Africa/Near East	**70.6**	**66.6**	**65.2**	**67.5**	74.4	76.9	86.0	73.9
Total crude oil and equivalents	**260.5**	**243.1**	**226.6**	**226.6**	248.5	250.0	243.4	249.7
Natural gas (MMcf/d)								
North American Natural Gas	**508**	**531**	**522**	**556**	534	499	535	515
Northwest Europe	**104**	**85**	**79**	**74**	96	78	55	90
North Africa/Near East	**3**	**6**	**2**	**–**	6	9	7	3
Northern Latin America	**67**	**40**	**49**	**45**	49	62	69	74
Total natural gas	**682**	**662**	**652**	**675**	685	648	666	682
Total production [2] (Mboe/d)	**374**	**353**	**335**	**339**	363	358	354	363

1 Includes production of synthetic crude oil from Syncrude mining operation.

2 Natural gas is converted to oil equivalent using 6,000 cubic feet of gas to one boe.

Production Outlook

In 2005, production from Petro-Canada's upstream businesses is expected to decrease slightly, compared to 2004 levels. This is mainly due to declines in Syria and Northwest Europe. Factors that may impact production during 2005 include reservoir performance, drilling results, facility reliability and the execution of planned turnarounds at certain gas plants, Terra Nova, Hibernia, and Syncrude and other factors. Investments in existing growth projects will provide additional production in 2006 and 2007. Exploration and new venture investments will also add production to the Company's portfolio of assets.

The following table shows Petro-Canada's 2005 production outlook for conventional crude oil, NGL, bitumen, synthetic crude oil and natural gas in crude oil equivalent before deduction of royalties.

CONSOLIDATED PRODUCTION
(thousands of boe/d)

	2004 Actual	2005 Outlook (+/−)
North American Natural Gas		
– Gas	**116**	113
– Liquids	**15**	14
East Coast Oil	**78**	77
Oil Sands		
– Syncrude	**29**	28
– MacKay River	**16**	24
International		
– North Africa/Near East	**130**	114
– Northwest Europe	**55**	43
– Northern Latin America	**12**	11
Total	**451**	415 - 440

The following table shows the average sale price for Petro-Canada's conventional crude oil, NGL, bitumen, synthetic crude oil, and natural gas, produced, by country and/or region, for the years indicated.

AVERAGE PRICES FOR CRUDE OIL, NATURAL GAS LIQUIDS, BITUMEN, SYNTHETIC CRUDE OIL AND NATURAL GAS

	Years Ended December 31,		
Average annual price received	**2004**	2003	2002
Crude oil and NGL ($/bbl)			
East Coast Oil	**$48.39**	$39.91	$38.84
Oil Sands	**39.90**	34.97	39.66
North American Natural Gas	**47.02**	38.21	32.01
Northwest Europe	**50.37**	41.41	41.10
North Africa/Near East	**47.33**	38.49	39.08
North America ($/bbl)			
Average crude oil and NGL sale price	**48.17**	39.63	37.42
Average bitumen sale price	**18.37**	16.69	14.61
Average synthetic crude oil sale price	**52.40**	42.67	40.66
North America average crude oil and NGL, bitumen and synthetic crude oil price	**45.47**	38.42	37.95
International ($/bbl)			
Northwest Europe – average crude oil and NGL sale price	**50.37**	41.41	41.10
North Africa/Near East– average crude oil and NGL sale price	**47.33**	38.49	39.08
International – average crude oil and NGL sale price	**48.06**	39.10	39.53
Total crude oil and NGL	**$46.89**	$38.80	$38.76
Natural gas ($/Mcf)			
North American Natural Gas	**$ 6.72**	$ 6.50	$ 4.01
Northwest Europe	**5.65**	5.42	4.65
North Africa/Near East	**4.81**	4.84	4.85
Northern Latin America	**4.81**	4.01	3.68
Total natural gas	**$ 6.41**	$ 6.16	$ 4.07

The following tables show Petro-Canada's average product prices, netbacks, net income and production before royalties for North American Natural Gas (natural gas equivalent), East Coast Oil (conventional crude oil), Oil Sands (synthetic crude oil and bitumen) and International regions (crude oil equivalent) for the years indicated.[1]

Petro-Canada monitors production costs and charges to earnings by business segment or region, rather than on a product basis. As a result, unit netbacks and net earnings for a business segment or region producing a mix of crude oil, natural gas and NGL are calculated on an oil or gas equivalent basis. In the North American Natural Gas business segment, most crude oil and NGL production is ancillary to the production of natural gas. In the North Africa/Near East region, natural gas and NGL production is relatively minor and linked to crude oil production. In Northwest Europe, crude oil production and associated natural gas and NGL production represents about 74% of total production on an oil-equivalent basis.

1 Certain 2003 and 2002 comparatives have been restated.

NORTH AMERICAN NATURAL GAS

($/Mcfe, unless otherwise indicated)

	2004 Three Months Ended					2003 Three Months Ended					
	Mar. 31	**June 30**	**Sept. 30** [1]	**Dec. 31** [1]	**Total 2004** [1]	**Mar. 31**	**June 30**	**Sept. 30**	**Dec. 31**	**Total 2003**	**Total 2002**
Average price received	**$ 6.50**	**$ 7.03**	**$ 6.81**	**$ 7.19**	**$ 6.89**	$ 8.10	$ 6.52	$ 6.03	$ 5.34	$ 6.51	$ 4.19
Royalties	**(1.63)**	**(1.64)**	**(1.68)**	**(1.65)**	**(1.65)**	(2.01)	(1.72)	(1.32)	(1.38)	(1.61)	(0.96)
Operating expenses	**(0.65)**	**(0.76)**	**(0.82)**	**(0.75)**	**(0.74)**	(0.54)	(0.59)	(0.62)	(0.62)	(0.59)	(0.51)
Netback	**4.22**	**4.63**	**4.31**	**4.79**	**4.50**	5.55	4.21	4.09	3.34	4.31	2.72
Overhead expenses (G&A) [2]	**(0.17)**	**(0.16)**	**(0.16)**	**(0.26)**	**(0.19)**	(0.15)	(0.15)	(0.16)	(0.14)	(0.15)	(0.12)
Netback after overhead expenses	**4.05**	**4.47**	**4.15**	**4.53**	**4.31**	5.40	4.06	3.93	3.20	4.16	2.60
Processing and other income	**0.04**	**0.02**	**0.06**	**0.11**	**0.06**	0.04	0.03	0.07	(0.05)	0.02	0.01
Exploration expenses	**(0.25)**	**(0.22)**	**(0.36)**	**(0.36)**	**(0.30)**	(0.35)	(0.17)	(0.31)	(0.32)	(0.29)	(0.31)
Depletion, depreciation and amortization	**(1.04)**	**(1.07)**	**(1.14)**	**(1.16)**	**(1.10)**	(0.95)	(0.96)	(0.97)	(0.96)	(0.96)	(0.90)
Income and other taxes	**(0.99)**	**(1.21)**	**(1.05)**	**(1.23)**	**(1.12)**	(1.72)	(1.10)	(1.23)	(0.73)	(1.20)	(0.63)
Net earnings	**$ 1.81**	**$ 1.99**	**$ 1.66**	**$ 1.89**	**$ 1.85**	$ 2.42	$ 1.86	$ 1.49	$ 1.14	$ 1.73	$ 0.77
Production (billion cubic feet equivalent – Bcfe)	**69.8**	**70.4**	**72.2**	**75.6**	**288.0**	74.5	71.3	71.5	72.5	289.8	304.8

EAST COAST OIL

($/bbl, unless otherwise indicated)

	2004 Three Months Ended					2003 Three Months Ended					
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	**Total 2004**	Mar. 31	June 30	Sept. 30	Dec. 31	Total 2003	Total 2002
Average price received	**$ 42.73**	**$ 47.51**	**$ 54.43**	**$ 50.29**	**$ 48.39**	$ 46.84	$ 35.79	$ 38.93	$ 38.66	$ 39.91	$ 38.84
Royalties	**(1.19)**	**(1.66)**	**(2.56)**	**(2.38)**	**(1.89)**	(0.99)	(0.67)	(1.16)	(1.03)	(0.95)	(0.55)
Operating expenses	**(2.54)**	**(2.48)**	**(3.29)**	**(2.66)**	**(2.72)**	(2.64)	(2.49)	(2.88)	(2.82)	(2.70)	(3.34)
Netback	**39.00**	**43.37**	**48.58**	**45.25**	**43.78**	43.21	32.63	34.89	34.81	36.26	34.95
Overhead expenses (G&A) [2]	**(0.14)**	**(0.16)**	**(0.20)**	**(0.18)**	**(0.17)**	–	(0.25)	(0.22)	(0.24)	(0.18)	(0.12)
Netback after overhead expenses	**38.86**	**43.21**	**48.38**	**45.07**	**43.61**	43.21	32.38	34.67	34.57	36.08	34.83
Processing and other income	**5.81**	**(0.03)**	**0.24**	**–**	**1.66**	–	–	–	3.05	0.78	–
Depletion, depreciation and amortization	**(8.87)**	**(9.00)**	**(9.18)**	**(9.17)**	**(9.05)**	(8.26)	(8.25)	(8.43)	(8.76)	(8.42)	(9.13)
Income and other taxes	**(11.35)**	**(10.85)**	**(12.75)**	**(11.56)**	**(11.58)**	(10.87)	(4.78)	(8.93)	(10.57)	(8.70)	(7.91)
Net earnings	**$ 24.45**	**$ 23.33**	**$ 26.69**	**$ 24.34**	**$ 24.64**	$ 24.08	$ 19.35	$ 17.31	$ 18.29	$ 19.74	$ 17.79
Production (MMbbls)	**8.0**	**7.8**	**6.5**	**6.3**	**28.6**	7.5	8.4	7.5	8.0	31.4	26.3

SYNCRUDE

($/bbl, unless otherwise indicated)

	2004 Three Months Ended					2003 Three Months Ended					
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	**Total 2004**	Mar. 31	June 30	Sept. 30	Dec. 31	Total 2003	Total 2002
Average price received	**$ 45.34**	**$ 51.41**	**$ 54.81**	**$ 58.58**	**$ 52.40**	$ 50.79	$ 41.46	$ 40.80	$ 38.80	$ 42.67	$ 40.66
Royalties	**(0.45)**	**(0.52)**	**(0.55)**	**(0.96)**	**(0.61)**	(0.52)	(0.42)	(0.59)	(0.39)	(0.48)	(0.44)
Operating expenses	**(18.54)**	**(22.70)**	**(19.97)**	**(23.66)**	**(21.13)**	(26.40)	(26.10)	(18.01)	(26.56)	(23.94)	(19.77)
Netback	**26.35**	**28.19**	**34.29**	**33.96**	**30.66**	23.87	14.94	22.20	11.85	18.25	20.45
Depletion, depreciation and amortization	**(1.79)**	**(1.80)**	**(1.79)**	**(1.79)**	**(1.79)**	(1.75)	(1.79)	(1.79)	(1.79)	(1.78)	(1.75)
Income and other taxes	**(7.35)**	**(8.83)**	**(10.57)**	**(10.60)**	**(9.31)**	(7.56)	1.06	(7.05)	(7.50)	(5.26)	(6.30)
Net earnings	**$ 17.21**	**$ 17.56**	**$ 21.93**	**$ 21.57**	**$ 19.56**	$ 14.56	$ 14.21	$ 13.36	$ 2.56	$ 11.21	$ 12.40
Production (MMbbls)	**2.8**	**2.5**	**2.7**	**2.5**	**10.5**	2.0	2.3	2.7	2.3	9.3	10.0

MACKAY RIVER

($/bbl, unless otherwise indicated)

	2004 Three Months Ended					2003 Three Months Ended				
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	**Total 2004**	Mar. 31	June 30	Sept. 30	Dec. 31	Total 2003
Average price received	**$ 19.10**	**$ 19.61**	**$ 25.15**	**$ 11.41**	**$ 18.37**	$ 22.60	$ 14.88	$ 15.66	$ 13.08	$ 16.69
Royalties	**(0.16)**	**(0.15)**	**(0.22)**	**(0.11)**	**(0.16)**	(0.18)	(0.05)	(0.08)	(0.10)	(0.12)
Operating expenses	**(18.40)**	**(30.32)**	**(20.08)**	**(17.76)**	**(20.98)**	(18.53)	(44.32)	(26.38)	(16.65)	(22.34)
Netback	**0.54**	**(10.86)**	**4.85**	**(6.46)**	**(2.77)**	3.89	(29.49)	(10.80)	(3.67)	(5.77)
Overhead expenses (G&A) [2]	**(0.78)**	**(1.09)**	**(0.96)**	**(0.80)**	**(0.89)**	(0.97)	(2.71)	(2.30)	(0.85)	(1.39)
Netback after overhead expenses	**(0.24)**	**(11.95)**	**3.89**	**(7.26)**	**(3.66)**	2.92	(32.20)	(13.10)	(4.52)	(7.16)
Processing and other income	**–**	**–**	**–**	**(0.01)**	**–**	–	–	0.22	–	0.04
Exploration expenses	**(0.04)**	**(0.05)**	**–**	**(0.02)**	**(0.03)**	(0.31)	(0.10)	(0.01)	(0.01)	(0.11)
Depletion, depreciation and amortization	**(3.10)**	**(3.37)**	**(3.14)**	**(3.09)**	**(3.16)**	(3.10)	(4.12)	(3.51)	(3.09)	(3.29)
Income and other taxes	**1.20**	**4.47**	**(0.36)**	**2.78**	**1.94**	0.16	13.37	5.04	1.69	3.24
Net earnings	**$ (2.18)**	**$(10.90)**	**$ 0.39**	**$ (7.60)**	**$ (4.91)**	$ (0.33)	$ (23.05)	$ (11.36)	$ (5.93)	$ (7.28)
Production (MMbbls)	**1.5**	**1.2**	**1.6**	**1.8**	**6.1**	1.1	0.5	0.8	1.5	3.9

NORTHWEST EUROPE [3,4]

($/boe, unless otherwise indicated)

	2004 Three Months Ended					2003 Three Months Ended					
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	**Total 2004**	Mar. 31	June 30	Sept. 30	Dec. 31	Total 2003	Total 2002
Average price received [5]	**$ 41.00**	**$ 44.71**	**$ 49.99**	**$ 50.46**	**$ 46.08**	$ 45.12	$ 34.02	$ 36.32	$ 38.12	$ 38.69	$ 38.41
Operating expenses	**(6.50)**	**(7.81)**	**(9.04)**	**(8.65)**	**(7.89)**	(5.12)	(5.73)	(9.26)	(8.22)	(6.90)	(7.19)
Netback	**34.50**	**36.90**	**40.95**	**41.81**	**38.19**	40.00	28.29	27.06	29.90	31.79	31.22
Overhead expenses (G&A) [2]	**(0.37)**	**(0.90)**	**(0.38)**	**(2.44)**	**(0.96)**	(0.77)	(0.62)	(1.35)	(0.67)	(0.82)	(0.89)
Netback after overhead expenses	**34.13**	**36.00**	**40.57**	**39.37**	**37.23**	39.23	27.67	25.71	29.23	30.97	30.33
Processing and other income	**5.78**	**(4.97)**	**(2.75)**	**0.83**	**(0.07)**	1.80	(0.17)	0.43	1.61	0.98	0.50
Exploration expenses	**(0.52)**	**(3.79)**	**(1.45)**	**(3.55)**	**(2.25)**	(0.55)	(1.83)	(0.38)	(1.77)	(1.17)	(0.90)
Depletion, depreciation and amortization	**(13.48)**	**(13.67)**	**(13.78)**	**(12.94)**	**(13.48)**	(11.87)	(11.71)	(11.07)	(10.70)	(11.37)	(11.20)
Income and other taxes	**(10.69)**	**(5.57)**	**(8.91)**	**(7.85)**	**(8.32)**	(11.92)	(4.79)	(5.80)	(8.17)	(7.90)	(5.45)
Net earnings	**$ 15.22**	**$ 8.00**	**$ 13.68**	**$ 15.86**	**$ 13.11**	$ 16.69	$ 9.17	$ 8.89	$ 10.20	$ 11.51	$ 13.28
Production (MMboe)	**5.8**	**5.3**	**4.6**	**4.3**	**20.0**	5.2	4.8	3.6	5.0	18.6	13.5

NORTH AFRICA/NEAR EAST [3,6]

($/boe, unless otherwise indicated)

	2004 Three Months Ended					2003 Three Months Ended					
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	**Total 2004**	Mar. 31	June 30	Sept. 30	Dec. 31	Total 2003	Total 2002
Average price received [5]	**$ 40.47**	**$ 46.49**	**$ 53.04**	**$ 47.95**	**$ 46.86**	$ 45.08	$ 34.10	$ 37.64	$ 36.94	$ 38.39	$ 38.73
Royalties	**(19.49)**	**(22.20)**	**(25.36)**	**(21.04)**	**(21.98)**	(21.51)	(16.18)	(17.91)	(17.92)	(18.35)	(19.79)
Net revenue	**20.98**	**24.29**	**27.68**	**26.91**	**24.88**	23.57	17.92	19.73	19.02	20.04	18.94
Operating expenses	**(4.91)**	**(4.60)**	**(4.20)**	**(4.54)**	**(4.57)**	(4.61)	(2.98)	(4.19)	(3.72)	(3.87)	(4.18)
Netback	**16.07**	**19.69**	**23.48**	**22.37**	**20.31**	18.96	14.94	15.54	15.30	16.17	14.76
Overhead expenses (G&A) [2]	**(0.48)**	**(0.56)**	**(0.52)**	**(0.40)**	**(0.49)**	(0.40)	(0.48)	(0.51)	(0.53)	(0.48)	(0.22)
Netback after overhead	**15.59**	**19.13**	**22.96**	**21.97**	**19.82**	18.56	14.46	15.03	14.77	15.69	14.54
Processing and other income	**0.76**	**(0.04)**	**0.12**	**(1.52)**	**(0.15)**	(0.44)	0.01	2.05	(1.01)	0.17	0.27
Exploration expenses	**(0.18)**	**(0.86)**	**(0.29)**	**(0.03)**	**(0.34)**	(0.84)	0.09	(0.16)	(0.06)	(0.24)	(0.23)
Depletion, depreciation and amortization	**(4.15)**	**(4.11)**	**(4.04)**	**(4.22)**	**(4.13)**	(3.13)	(3.27)	(3.20)	(3.15)	(3.19)	(3.01)
Income and other taxes	**(9.45)**	**(12.14)**	**(15.96)**	**(12.23)**	**(12.39)**	(12.11)	(10.23)	(9.58)	(10.06)	(10.49)	(8.82)
Net earnings	**$ 2.57**	**$ 1.98**	**$ 2.79**	**$ 3.97**	**$ 2.81**	$ 2.04	$ 1.06	$ 4.14	$ 0.49	$ 1.94	$ 2.75
Production (MMboe)	**12.5**	**11.9**	**11.6**	**11.5**	**47.5**	13.1	13.5	13.5	13.2	53.3	37.5

NORTHERN LATIN AMERICA [3,7]

($/Mcf, unless otherwise indicated)

	2004 Three Months Ended					2003 Months Ended					
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	**Total 2004**	Mar. 31	June 30	Sept. 30	Dec. 31	Total 2003	Total 2002
Average price received	**$ 4.72**	**$ 4.99**	**$ 4.24**	**$ 5.30**	**$ 4.81**	$ 4.93	$ 4.39	$ 3.85	$ 3.23	$ 4.01	$ 3.68
Royalties	**–**	**(0.62)**	**(1.43)**	**(2.02)**	**(1.05)**	–	–	–	–	–	(0.07)
Net revenue	**4.72**	**4.37**	**2.81**	**3.28**	**3.76**	4.93	4.39	3.85	3.23	4.01	3.61
Operating expenses	**(0.13)**	**(0.19)**	**(0.07)**	**(0.09)**	**(0.12)**	(0.16)	(0.18)	(0.29)	0.02	(0.15)	(0.48)
Netback	**4.59**	**4.18**	**2.74**	**3.19**	**3.64**	4.77	4.21	3.56	3.25	3.86	3.13
Overhead expenses (G&A) [2]	**(0.08)**	**(0.12)**	**(0.13)**	**(0.19)**	**(0.13)**	(0.05)	(0.12)	(0.06)	(0.05)	(0.07)	(0.21)
Netback after overhead expenses	**4.51**	**4.06**	**2.61**	**3.00**	**3.51**	4.72	4.09	3.50	3.20	3.79	2.92
Processing and other income	**(0.04)**	**0.02**	**(0.07)**	**(0.07)**	**(0.04)**	(0.71)	(0.81)	(0.21)	(0.56)	(0.55)	–
Depletion, depreciation and amortization	**(0.59)**	**(0.57)**	**(0.58)**	**(0.54)**	**(0.57)**	(0.83)	(0.82)	(0.80)	(0.80)	(0.81)	(0.35)
Income and other taxes	**(1.51)**	**(2.60)**	**(1.13)**	**(1.28)**	**(1.62)**	(1.02)	(0.28)	(0.51)	(0.96)	(0.68)	(0.35)
Net earnings	**$ 2.37**	**$ 0.91**	**$ 0.83**	**$ 1.11**	**$ 1.28**	$ 2.16	$ 2.18	$ 1.98	$ 0.88	$ 1.75	$ 2.22
Production (Bcf)	**6.1**	**6.4**	**6.8**	**6.8**	**26.1**	4.4	5.7	6.3	6.8	23.2	4.9

1 North American Natural Gas includes U.S. Rockies post acquisition date of July 28, 2004.
2 Portion of head office expenses allocated to production.
3 Northwest Europe and North Africa/Near East include conventional crude oil, NGL and natural gas in crude oil equivalent. Northern Latin America includes only natural gas.
4 Reserves in Northwest Europe are subject to a conventional royalty and tax regime. No royalty is payable on reserves in the U.K. sector. Royalty is payable on onshore reserves in The Netherlands.
5 Average price for Northwest Europe and North Africa/Near East includes conventional crude oil, NGL and natural gas in crude oil equivalent.
6 Excludes Kazakhstan which was sold in 2004.
7 Natural gas reserves in Trinidad are held under a production-sharing arrangement with the government. The state share is split between royalty and tax for Canadian reporting purposes.

Reserves

At year-end 2004, proved reserves before royalties totaled 1,214 MMboe, including 331 MMbbls of synthetic crude oil from Oil Sands mining. This amount was down slightly from 1,220 MMboe at year-end 2003. Exploration, development and acquisition activities all contributed to the Company's overall replacement of its reserves. As a result of better-than-forecast reservoir performance at Hibernia, Petro-Canada revised its life of field reserves estimate upward from 835 MMbbls to 940 MMbbls (net Petro-Canada from 167 MMbbls to 188 MMbbls). This revision added more than 15 MMbbls to year-end 2004 proved reserves at Hibernia. However, in complying with SEC requirements to use prices and costs as of the date of the reserves estimate, the Company reclassified 22 MMbbls of proved bitumen reserves at its MacKay River development as probable reserves. This reflects abnormally high light/heavy crude oil differentials and increased costs for synthetic crude oil (used as a blending material for transporting the bitumen to market) at year-end 2004. This did not have any financial impact on the Company, and Petro-Canada continues to view its bitumen reserves and resources as an integral part of its overall growth portfolio. Absent of this reclassification, the Company would have replaced 110% of its 2004 production.

As part of Petro-Canada's long-term reserves replacement strategy, the Company added exploration capability and funding, especially internationally, to develop a balanced exploration program aimed at increasing the reserves base over time. In particular, Petro-Canada will target long-life reserves and aim for greater operatorship. The Company's goal is a growth portfolio that provides a balanced range of risk/reward opportunities. The new exploration lands recently acquired in Syria, Tunisia, Algeria and the North Sea are early examples of initiatives in the International business. In Canada, Petro-Canada continues to pursue opportunities off the East Coast and North of 60. In Western Canada, the Company plans to gradually increase the exploration program to improve reserves replacement.

In order to harmonize its oil and gas disclosure in both Canada and the U.S., Petro-Canada applied for, and received, certain exemptions to reserves disclosure requirements as set out in National Instrument *51-101; Standards of Disclosure for Oil and Gas Activities* (NI 51-101), which was adopted in 2003 by the securities regulatory authorities in Canada. These exemptions permit Petro-Canada to use its own staff of qualified reserves evaluators to prepare the Company's reserves estimates and to use SEC and Financial Accounting Standards Board (FASB) standards when reporting reserves.

Petro-Canada strongly believes that the use of its own staff of qualified reserves evaluators who are familiar with the Company's oil and gas assets as a result of working with them on a day-to-day basis, combined with independent third-party assessment of both its reserves processes and its reserves estimates, provides a level of confidence in its reserves data that is at least as good as that which would be provided if the work was done solely by a third party.

Petro-Canada's staff of qualified reserves evaluators determines the Company's reserves data and quantities based on corporate-wide policies, procedures and practices. These reserves policies, procedures and practices conform to the requirements of Canadian, as well as SEC regulations, and the Association of Professional Engineers, Geologists and Geophysicists of Alberta Standard of Practice for the Evaluation of Oil and Gas Reserves for Public Disclosure.

To confirm the quality of the reserves policies, procedures and practices and the internally generated reserves estimates, Petro-Canada employs the services of independent qualified engineering evaluators/auditors. For 2004, independent petroleum reservoir engineering consultants Sproule Associates Limited (Sproule) and Gaffney, Cline & Associates Ltd. (GCA) conducted assessments of Petro-Canada's hydrocarbon reserves. GCA completed an independent audit of 78% of the Company's proved crude oil, natural gas and NGL reserves outside of North America. Similarly, Sproule audited 77% of Petro-Canada's Canadian proved conventional reserves and reviewed Syncrude. Sproule also conducted an evaluation of Petro-Canada's proved, probable and possible reserves in the U.S. Rockies. The independent auditors'/evaluators' reports concluded that the Company's year-end 2004 proved reserves estimates are reasonable.

Sproule and GCA also audited Petro-Canada's reserves policies, procedures and practices. They concluded that Petro-Canada's reserve booking standards meet applicable disclosure regulations, that management is complying with those standards, and that the reserves process is carried out in a manner and standard consistent with the auditors' practices. In addition, PricewaterhouseCoopers LLP, as contract internal auditor, tested the non-engineering management control processes used in establishing reserves.

Detailed information about Petro-Canada's proved reserves of crude oil, NGL, natural gas, bitumen and synthetic crude oil before and after royalties follows this section.

Petro-Canada's Reserves Processes

Petro-Canada has a well-established reserves management process. The key components of the process are:

Reserves Steering Committee: Chaired by the senior vice-president, North American Natural Gas, the Reserves Steering Committee meets regularly to address issues regarding the reserves evaluation and reporting processes. Senior managers representing each upstream business unit, Finance Shared Services and Legal Services make up this Committee.

Reservoir Engineering Organization: One or more reservoir engineering supervisors are responsible for the functional guidance of reservoir engineering within each upstream business unit. The supervisors ensure that the appropriate standards, processes and quality assurance checks are applied to reservoir engineering activities, including reserve evaluation. The supervisors, as responsible qualified reserves evaluators, sign the annual reserve evaluations for their respective areas.

Reserves Definitions, Policies, Procedures and Practices: Petro-Canada has developed corporate-wide internal policies, procedures and practices to assist evaluation personnel. These are designed to meet internal and external reporting requirements. They are updated annually, reviewed with the reservoir engineering staff, and are maintained for reference on the reservoir engineering Web site within Petro-Canada's intranet.

Major Property Reviews: Each year, prior to business plan development, a series of reviews is conducted with interdisciplinary management on Petro-Canada's major properties. These reviews are intended to ensure that there is a current, accurate and appropriately communicated understanding of these assets and their associated opportunities.

Reserves Software Tools: Petro-Canada employs a high-quality technical tool kit for reservoir engineering. This software supports the analysis of technical and economic parameters required for reserve evaluation. Ongoing training and competency assessment is used to support the effective use of the tool kit.

Independent Evaluation/Audit/Review: Independent qualified reserves evaluators are engaged to audit and/or evaluate the Company's internal evaluation processes and to perform such tests as they deem appropriate to ensure Petro-Canada's reserves are appropriately evaluated. The independent evaluators' observations and recommendations are reviewed with senior management and are used to guide process improvement activities.

Reserves Review and Disclosure Process: In December of each year, the business unit management in each business unit reviews the reserves data prepared by the reservoir engineering staff. Also in December, Petro-Canada's year-end reserves and preliminary reports from the independent evaluators are reviewed by the Reserves Steering Committee. A copy of the preliminary reserves report is supplied to the external financial auditor. In January, the final reserves report is reviewed with the executive leadership team and the Audit, Finance and Risk Committee of the Board of Directors, which has been assigned the roles and responsibilities of the Reserves Steering Committee under NI 51-101.

The following tables show the Company's estimates of Petro-Canada's total proved conventional crude oil, NGL, natural gas, bitumen and synthetic crude oil reserves as at December 31, 2004, and average 2004 daily production by major fields.

PRINCIPAL RESERVES AND PRODUCTION LOCATIONS, BEFORE DEDUCTION OF ROYALTIES

Crude Oil Field/Facility [3]	Location	Proved Reserves [1,2] at December 31, 2004 (MMbbls)	Average 2004 Daily Production (Mbbl/d)
Syncrude	Alberta	**331**	**29**
Buzzard	Offshore U.K.	**85**	**–**
Ghani/Zenad Farrud	Libya	**43**	**14**
Amal	Libya	**42**	**15**
Hibernia	Offshore Newfoundland and Labrador	**35**	**41**
Terra Nova	Offshore Newfoundland and Labrador	**29**	**37**
Ghani Gir/Facha	Libya	**21**	**4**
Guillemot West	Offshore U.K.	**15**	**9**
Ferrier	Alberta	**13**	**3**
Other		**159**	**139**
Total		**773**	**291**

Natural Gas Field/Facility [3]	Location	Proved Reserves at December 31, 2004 (Bcf)	Average 2004 Daily Production [1] (MMcf/d)
Wildcat Hills area	Alberta	**481**	**147**
Hanlan area	Alberta	**327**	**112**
NCMA-1	Offshore Trinidad	**265**	**72**
Medicine Hat	Alberta	**191**	**39**
Jedney/Bubbles area	British Columbia	**163**	**29**
Ricinus/Bearberry area	Alberta	**102**	**64**
Laprise area	British Columbia	**102**	**30**
Alderson	Alberta	**100**	**23**
Ferrier	Alberta	**67**	**19**
Denver-Julesburg area	U.S.	**61**	**10**
Other		**615**	**328**
Total		**2,474**	**873**

1 The reserves and production shown in this table do not include NGL. Total Company proved reserves of crude oil and NGL at year-end 2004 were 801 MMbbls.

2 Syncrude reserves are synthetic crude oil reserves from oil sands mining.

3 Fields are onshore unless otherwise indicated.

Petro-Canada believes that the crude oil, NGL, natural gas, bitumen and synthetic crude oil reserves quantities are reasonable estimates consistent with current knowledge of the characteristics and extent of the productive formations, but such estimates are subject to upward or downward revisions as additional information regarding producing fields becomes available, as technology improves and as economic conditions change. Additional proved reserves are expected to be booked during the normal course of continuing development.

The following tables show, for the years indicated, Petro-Canada's estimates of proved reserves, before and after deduction of royalties, for each of conventional crude oil, NGL, bitumen, synthetic crude oil (from mining operations) and natural gas.

PROVED RESERVES BEFORE ROYALTIES [1,2,3,4,5]
(Crude oil and equivalents in MMbbls; Natural gas in Bcf)

	International					North America Conventional									
						North American Natural Gas									
	Northwest Europe [6]		North Africa/ Near East [7,8,9,10]		Northern Latin America [7,11]	Western Canada		U.S. Rockies		East Coast [12]	Oil Sands [13]	Total Conventional	Syncrude Mining Operation [14]	Total	
	Crude Oil & NGL	Natural Gas	Crude Oil & NGL	Natural Gas	Natural Gas	Crude Oil & NGL	Natural Gas	Crude Oil & NGL	Natural Gas	Crude Oil & NGL	Bitumen	Crude Oil, NGL & Bitumen	Synthetic Crude Oil	Crude Oil & Equivalents	Natural Gas
Beginning of year 2003	62	160	289	77	341	55	2,181	–	–	68	32	506	324	830	2,759
Revisions of previous estimate [15]	14	(8)	24	–	–	(1)	6	–	–	35	–	72	15	87	(2)
Sale of reserves in place	–	(4)	–	–	–	(8)	(25)	–	–	–	–	(8)	–	(8)	(29)
Purchase of reserves in place	3	7	–	–	–	–	13	–	–	–	–	3	–	3	20
Discoveries, extensions and improved recovery	–	–	–	–	6	1	106	–	–	–	–	1	–	1	112
Production	(14)	(29)	(52)	(12)	(23)	(6)	(251)	–	–	(32)	(4)	(108)	(9)	(117)	(315)
End of year 2003	65	126	261	65	324	41	2,030	–	–	71	28	466	330	796	2,545
Revisions of previous estimate [15]	12	31	1	(18)	(33)	–	16	–	(14)	26	(22)	17	12	29	(18)
Sale of reserves in place	–	(1)	(6)	–	–	–	(1)	–	–	–	–	(6)	–	(6)	(2)
Purchase of reserves in place	86	6	–	–	–	–	7	6	109	–	–	92	–	92	122
Discoveries, extensions and improved recovery	–	–	–	–	–	2	145	–	–	–	–	2	–	2	145
Production	(15)	(31)	(46)	(8)	(26)	(5)	(247)	–	(7)	(29)	(6)	(101)	(11)	(112)	(319)
End of year 2004	**148**	**131**	**210**	**39**	**265**	**38**	**1,950**	**6**	**88**	**68**	**–**	**470**	**331**	**801**	**2,473**
Proved undeveloped reserves [16]															
Beginning of year 2003	10	22	51	–	275	3	205	–	–	16	17	97	147	244	502
End of year 2003	–	–	36	–	190	1	82	–	–	16	17	70	165	235	272
End of year 2004	**101**	**14**	**21**	**–**	**178**	**1**	**82**	**2**	**24**	**19**	**–**	**144**	**189**	**333**	**298**

PROVED RESERVES AFTER ROYALTIES [1,2,3,4,5]
(Crude oil and equivalents in MMbbls; Natural gas in Bcf)

	International					North America Conventional – North American Natural Gas				North America Conventional					
	Northwest Europe [6]		North Africa/ Near East [7,8,9,10]		Northern Latin America [7,11]	Western Canada		U.S. Rockies		East Coast [12]	Oil Sands [13]	Total Conventional	Syncrude Mining Operation [14]	Total	
	Crude Oil & NGL	Natural Gas	Crude Oil & NGL	Natural Gas	Natural Gas	Crude Oil & NGL	Natural Gas	Crude Oil & NGL	Natural Gas	Crude Oil & NGL	Bitumen	Crude Oil, NGL & Bitumen	Synthetic Crude Oil	Crude Oil & Equivalents	Natural Gas
Beginning of year 2003	62	160	183	19	287	43	1,673	–	–	60	31	379	278	657	2,139
Revisions of previous estimate [15]	14	(8)	14	5	6	–	4	–	–	38	1	67	21	88	7
Sale of reserves in place	–	(4)	–	–	–	(7)	(19)	–	–	–	–	(7)	–	(7)	(23)
Purchase of reserves in place	2	7	–	–	–	–	10	–	–	–	–	2	–	2	17
Discoveries, extensions and improved recovery	–	–	–	–	5	1	81	–	–	–	–	1	–	1	86
Production	(14)	(29)	(28)	(2)	(23)	(5)	(190)	–	–	(31)	(4)	(82)	(9)	(91)	(244)
End of year 2003	64	126	169	22	275	32	1,559	–	–	67	28	360	290	650	1,982
Revisions of previous estimate [15]	13	31	3	(8)	(32)	–	20	–	(11)	21	(22)	15	7	22	–
Sale of reserves in place	–	(1)	(3)	–	–	–	(1)	–	–	–	–	(3)	–	(3)	(2)
Purchase of reserves in place	86	6	–	–	–	–	5	4	90	–	–	90	–	90	101
Discoveries, extensions and improved recovery	–	–	–	–	–	2	113	–	–	–	–	2	–	2	113
Production	(15)	(31)	(25)	(1)	(18)	(4)	(188)	–	(6)	(27)	(6)	(77)	(10)	(87)	(244)
End of year 2004	**148**	**131**	**144**	**13**	**225**	**30**	**1,508**	**4**	**73**	**61**	**–**	**387**	**287**	**674**	**1,950**
Proved undeveloped reserves [16]															
Beginning of year 2003	10	22	33	–	232	3	157	–	–	14	16	76	126	202	411
End of year 2003	–	–	23	–	161	1	62	–	–	16	16	56	143	199	223
End of year 2004	**101**	**14**	**14**	**–**	**151**	**1**	**65**	**2**	**20**	**16**	**–**	**134**	**161**	**295**	**250**

1 In order to harmonize its oil and gas disclosure in both Canada and the U.S., Petro-Canada applied for, and received, certain exemptions to reserves disclosure requirements as set out in NI 51-101. These exemptions permit Petro-Canada to use its own staff of qualified reserves evaluators to prepare the Company's reserves estimates and to use SEC and FASB standards when preparing and reporting reserves. Such reserves information may differ from reserves information prepared in accordance with Canadian disclosure standards under NI 51-101. These differences relate to the SEC requirement for disclosure only of proved reserves calculated at constant year-end prices and costs while NI 51-101 requires disclosure of proved reserves at constant prices and costs, and proved plus probable reserves at forecast prices and costs. Also, the definition of proved reserves differs between SEC and NI 51-101 requirements. However, this difference should not be material. The Canadian Oil and Gas Evaluation Handbook (the source document for reserves definitions under NI 51-101) supports this view.

[2] Petro-Canada employs the services of independent third-party evaluators/auditors to assess its reserves policies, practices and procedures and its reserves estimates.

[3] Proved reserves before royalties are Petro-Canada's working interest reserves before the deduction of Crown or other royalties. Such royalties are subject to change by legislation or regulation and can also vary depending on production rates, selling prices and timing of initial production. Reserves quantities after royalty reflect net over-riding royalty interests paid and received.

[4] Proved reserves are the estimated quantities of crude oil, natural gas and NGL which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those proved reserves that are expected to be recovered from existing wells or facilities. Proved undeveloped reserves are proved reserves which are not recoverable from existing wells or facilities, but which are expected to be recovered through additional development drilling or through the upgrading of existing or additional new facilities.

[5] Unproved reserves are based on geological and/or engineering data similar to that used in estimates of proved reserves, but technical, contractual, economic or regulatory uncertainties preclude such reserves being classified as proved. Unproved reserves may be further classified as probable reserves and possible reserves.

[6] Reserves in Northwest Europe are subject to a conventional royalty and tax regime. No royalty is payable on reserves in the U.K. sector. Royalty is payable on onshore reserves in The Netherlands.

[7] Proved reserves include quantities of crude oil and natural gas which will be produced under arrangements which involve the Company or its subsidiaries in upstream risks and rewards, but do not transfer title of the product to those companies.

[8] Reserves in Syria and Algeria (and formerly in Kazakhstan) are held under production-sharing arrangements with the governments. The State share is split between royalty and tax for Canadian reporting purposes.

[9] With the exception of the En Naga field, reserves in Libya are held under a concession and are subject to a royalty and tax regime. The En Naga field is held under a production-sharing arrangement, with the government's share being split between royalty and tax for Canadian reporting purposes.

[10] The volume of oil and gas reserves before royalties reported above held under PSCs in the North Africa/Near East region at the end of 2004 was 72 MMbbls of crude oil and NGL and 39 Bcf of natural gas. At year-end 2003, the volume was 112 MMbbls of crude oil and NGL and 65 Bcf of natural gas. The after royalty reserves volumes were: year-end 2004 – 28 MMbbls of crude oil and NGL and 13 Bcf of natural gas; and year-end 2003 – 44 MMbbls of crude oil and NGL and 22 Bcf of natural gas.

[11] Natural gas reserves in Trinidad are held under a production-sharing arrangement with the government. The State share is split between royalty and tax for Canadian reporting purposes. The volume of proved natural gas reserves before royalties reported above held under PSCs in Trinidad at the end of 2004 was 265 Bcf. At year-end 2003, the volume was 324 Bcf. The after royalty reserves volumes were: year-end 2004 – 225 Bcf; and year-end 2003 – 275 Bcf.

[12] Proved reserves at Hibernia and Terra Nova are based on primary recovery for drilled fault blocks plus incremental recovery in fault blocks showing response to water or gas injection. Additional reserves quantities will be booked as proved reserves as development proceeds.

[13] Proved reserves at MacKay River are based on estimates of recovery from existing producer-injector well pairs. As a result of very wide light/heavy crude oil differentials and high prices for synthetic crude oil used for blending at year-end 2004, bitumen prices were very low. Based on SEC practices for the estimation of proved reserves, the Company transferred its remaining proved reserves of bitumen at year end to probable reserves.

[14] Proved reserves of synthetic crude oil from the Syncrude oil sands mining operation in Northeastern Alberta are separately identified from reserves of conventional crude oil. Petro-Canada views these reserves as an integral part of the Company's business. Proved reserves of synthetic crude oil are based on high geological certainty and application of proven or piloted technology. For proved reserves, drill hole spacing is less than 500 metres and appropriate co-owner and regulatory approvals are in place.

[15] Revisions include changes in previous estimates, either upward or downward, resulting from new information (except an increase in acreage) normally obtained from drilling or production history or resulting from a change in economic factors.

[16] Proved undeveloped conventional crude oil and NGL reserves represent approximately 31% of Petro-Canada's total conventional crude oil and NGL proved reserves. The vast majority of these oil and NGL reserves are associated with large development projects currently producing or under active development including Buzzard, White Rose, Terra Nova and Hibernia. The Company's proved undeveloped gas reserves represent approximately 12% of total proved natural gas reserves. These reserves typically will be developed through tie-in of existing wells, drilling of additional wells or addition of compression facilities. Sixty per cent of the proved undeveloped gas reserves are associated with the currently producing NCMA-1 development in Trinidad. Generally, the Company would plan to develop proved undeveloped natural gas reserves in the next few years.

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Gas Reserves

The following disclosures on standardized measure of discounted cash flows and changes therein relating to proved oil and gas reserves are determined in accordance with the U.S. FASB Statement 69, "Disclosures About Oil and Gas Producing Activities." The future cash flows are calculated by applying year-end prices, or prices provided by contractual arrangements, net of royalties, to year-end quantities of proved oil and gas reserves. Future production, development and asset retirement costs are based on year-end costs and estimated future income taxes are based on legislated future income tax rates. The resulting future net cash flows are discounted at 10% per annum. The calculation does not represent a fair market value of the Company's oil and gas reserves or of the future net cash flows. No consideration is given to the value of exploration properties or probable reserves. No consideration is given to the value of the Company's share of the Syncrude oil sands mining operation, as it is considered a mining operation under SEC disclosure. The following benchmark commodity prices as at December 31, 2004, were used in deriving the Standardized Measure: WTI at Cushing $43.45/bbl US; dated Brent at Sullom Voe $40.47/bbl US; NYMEX gas price at the Henry Hub $6.149/MMBtu US; and Alberta price of natural gas at the AECO-C Hub $6.44/gigajoule Cdn. The following currency exchange rates were also used: $Cdn/$US 1.2036; $Cdn/euro 1.6292; $Cdn/British pound 2.3062.

SUMMARY OF CHANGES IN PRESENT VALUE OF ESTIMATED FUTURE CASH FLOWS

(millions of dollars)

	2004	2003	2002
Balance at beginning of year	**$ 6,216**	$ 7,022	$ 2,736
Changes result from:			
Sales and transfers of oil and gas produced, net of production costs	**(4,348)**	(4,062)	(1,753)
Net changes in prices, operating costs and royalties	**2,482**	(1,608)	2,807
Extensions, discoveries, additions and improved recoveries	**395**	274	500
Changes in estimated future development costs	**(1,235)**	(767)	(674)
Development costs incurred during the year	**966**	845	524
Revisions of previous quantity estimates	**979**	1,149	1,061
Accretion of discount	**1,117**	910	343
Net change in income tax	**(1,186)**	1,843	(5,435)
Purchase and sale of reserves in place	**2,017**	313	6,780
Changes in timing and other	**129**	297	133
Net change	**1,316**	(806)	4,286
Balance at end of year	**$ 7,532**	$ 6,216	$ 7,022

PRESENT VALUE OF ESTIMATED FUTURE NET CASH FLOWS
(millions of dollars)

	Western Canada [1]			U.S. Rockies			East Coast Oil [2]			Northwest Europe			North Africa/Near East			Northern Latin America			Total		
	2004	2003	2002	**2004**	2003	2002	**2004**	2003	2002	**2004**	2003	2002	**2004**	2003	2002	**2004**	2003	2002	**2004**	2003	2002
Future cash flows	**$11,470**	$10,382	$11,529	**$ 688**	$ –	$ –	**$2,580**	$2,470	$2,861	**$ 7,624**	$3,370	$3,891	**$ 7,077**	$6,693	$8,951	**$1,031**	$1,348	$1,244	**$30,470**	$24,263	$28,476
Future production, development and asset retirement costs	**(2,344)**	(2,290)	(1,642)	**(281)**	–	–	**(786)**	(523)	(749)	**(3,190)**	(1,341)	(1,505)	**(1,434)**	(1,436)	(1,866)	**(151)**	(147)	(161)	**(8,186)**	(5,737)	(5,923)
Future income taxes	**(2,900)**	(2,517)	(3,582)	**(110)**	–	–	**(467)**	(506)	(653)	**(1,682)**	(667)	(879)	**(4,563)**	(4,088)	(5,530)	**(479)**	(647)	(552)	**(10,201)**	(8,425)	(11,196)
Future net cash flows	**6,226**	5,575	6,305	**297**	–	–	**1,327**	1,441	1,459	**2,752**	1,362	1,507	**1,080**	1,169	1,555	**401**	554	531	**12,083**	10,101	11,357
Discount of 10% for estimated timing of cash flows	**(2,676)**	(2,407)	(2,668)	**(118)**	–	–	**(285)**	(506)	(472)	**(929)**	(293)	(400)	**(355)**	(400)	(532)	**(188)**	(279)	(263)	**(4,551)**	(3,885)	(4,335)
Discounted future net cash flows	**$ 3,550**	$ 3,168	$ 3,637	**$ 179**	$ –	$ –	**$1,042**	$ 935	$ 987	**$ 1,823**	$1,069	$1,107	**$ 725**	$ 769	$1,023	**$ 213**	$ 275	$ 268	**$ 7,532**	$ 6,216	$ 7,022

[1] Western Canada includes the cash flows of MacKay River in 2002 and 2003. There were no proved reserves at MacKay River at year-end 2004.

[2] Additional East Coast Oil reserves quantities will be booked as proved reserves as development proceeds.

Abandonments and Reclamation Costs

The Company's upstream future asset retirement costs are estimated based on current costs and technology, and in accordance with existing legislation and industry practice. As of December 31, 2004, the total of these costs is estimated to be $2,313 million undiscounted or $543 million discounted at 10%. The Company's upstream operations expect to spend approximately $30 million, $48 million and $39 million in the next three years, respectively, for future asset retirement costs.

The following table summarizes Petro-Canada's wells capable of production.

PRODUCTIVE WELLS [1] AT DECEMBER 31, 2004

	Crude Oil Wells		Natural Gas Wells		Total Wells	
	Gross [2]	**Net [3]**	**Gross**	**Net**	**Gross**	**Net**
North American Natural Gas	**199**	**140**	**4,436**	**3,115**	**4,635**	**3,255**
East Coast Oil – conventional oil and gas	**38**	**9**	**–**	**–**	**38**	**9**
Oil Sands – *in situ* bitumen recovery	**25**	**25**	**–**	**–**	**25**	**25**
Total North America	**262**	**174**	**4,436**	**3,115**	**4,698**	**3,289**
International						
Northwest Europe – conventional oil and gas	**38**	**13**	**34**	**5**	**72**	**18**
North Africa/Near East – conventional oil and gas	**567**	**227**	**–**	**–**	**567**	**227**
Northern Latin America – natural gas	**–**	**–**	**7**	**1**	**7**	**1**
Total International	**605**	**240**	**41**	**6**	**646**	**246**
Total productive wells	**867**	**414**	**4,477**	**3,121**	**5,344**	**3,535**

1 Wells with multiple completions are counted as one well.

2 Gross wells are wells in which Petro-Canada owns a working interest.

3 Net wells are the sums of the fractional working interests owned by Petro-Canada in gross wells, rounded to the nearest whole number.

Oil and Natural Gas Rights

Petro-Canada's oil and natural gas rights are summarized in the following table. Landholdings are subject to government regulation.

OIL AND GAS RIGHTS AT DECEMBER 31,
(millions of acres)

	Developed Lands [1]				Undeveloped Lands [1]				Total			
	2004		2003		**2004**		2003		**2004**		2003	
	Gross [2]	**Net [3]**	Gross [2]	Net [3]	**Gross [2]**	**Net [3]**	Gross [2]	Net [3]	**Gross [2]**	**Net [3]**	Gross [2]	Net [3]
Canada												
Mainland Canada	**2.1**	**1.1**	2.0	1.0	**3.9**	**2.9**	4.2	3.0	**6.0**	**4.0**	6.2	4.0
Oil Sands	**0.3**	**0.1**	0.2	0.1	**0.3**	**0.1**	0.4	0.2	**0.6**	**0.2**	0.6	0.3
East Coast offshore	**0.1**	**–**	0.1	–	**3.5**	**1.2**	4.2	1.5	**3.6**	**1.2**	4.3	1.5
Other frontier [4]	**0.0**	**0.0**	–	–	**7.7**	**6.2**	7.7	6.2	**7.7**	**6.2**	7.7	6.2
Total Canada	**2.5**	**1.2**	2.3	1.1	**15.4**	**10.4**	16.5	10.9	**17.9**	**11.6**	18.8	12.0
United States	**–**	**–**	–	–	**1.2**	**1.1**	0.4	0.4	**1.2**	**1.1**	0.4	0.4
International												
North Africa/Near East	**0.9**	**0.4**	0.9	0.4	**10.0**	**6.7**	9.1	6.1	**10.9**	**7.1**	10.0	6.5
Northwest Europe	**0.1**	**–**	0.2	0.1	**2.2**	**0.8**	2.0	0.6	**2.3**	**0.8**	2.2	0.7
Northern Latin America	**–**	**–**	0.1	–	**0.2**	**–**	0.2	–	**0.2**	**–**	0.3	–
Total International	**1.0**	**0.4**	1.2	0.5	**12.4**	**7.5**	11.3	6.7	**13.4**	**7.9**	12.5	7.2
Total	**3.5**	**1.6**	3.5	1.6	**29.0**	**19.0**	28.2	18.0	**32.5**	**20.6**	31.7	19.6

[1] Developed lands are areas capable of production while undeveloped lands are areas with rights to explore.
[2] Gross acres include the interests of others.
[3] Net acres exclude the interests of others.
[4] Includes lands located off the West Coast of Canada where exploration is currently under moratorium.

Work Commitments

The practice of governments requiring companies to pledge to carry out work commitments in exchange for the right to carry out exploration for and development of hydrocarbons is a common one, particularly in unexplored or lightly explored regions of the world. Petro-Canada has made the following commitments in regard to the lands it holds.

WORK COMMITMENTS AS AT DECEMBER 31, 2004
(millions of dollars)

	Petro-Canada Share of Total Work Commitments	Petro-Canada Share of Total Work Commitments to be Incurred in 2005 [1]
Mainland Canada		
Mackenzie Delta/Corridor region	**20.0**	11.9
East Coast offshore	**23.0**	10.7
International		
North Africa/Near East	**33.7**	15.1
Northwest Europe	**42.8**	22.4
Total work commitments	**119.5**	60.1

1 Capital expenditure plans for 2005 include provision for these work commitments.

Land Expiries

The following table summarizes the land area by region for which Petro-Canada's rights to explore for or develop hydrocarbons will expire in 2005.

LAND EXPIRIES IN 2005
(millions of acres)

	Gross [1]	Net [2]
North American Natural Gas	1.7	1.3
East Coast Oil	1.0	0.3
Oil Sands	–	–
International	–	–
Total expiries in 2005	2.7	1.6

1 Gross includes the interests of others.
2 Net excludes the interests of others.

Drilling Activity

The following table shows Petro-Canada's drilling activity during the years indicated.

EXPLORATION AND DEVELOPMENT WELLS DRILLED

	2004		2003		2002	
	Gross [1]	**Net [2]**	Gross [1]	Net [2]	Gross [1]	Net [2]
NORTH AMERICAN NATURAL GAS						
Western Canada and U.S. Rockies						
Exploration wells [3]						
Oil	**2**	**–**	–	–	–	–
Natural gas	**53**	**35**	24	17	10	5
Dry [4]	**19**	**14**	20	16	17	12
Subtotal	**74**	**49**	44	33	27	17
Development wells [5]						
Oil	**5**	**2**	9	2	4	4
Natural gas	**589**	**461**	388	231	337	197
Dry	**7**	**5**	17	14	10	7
Subtotal	**601**	**468**	414	247	351	208
Mackenzie Delta/Corridor and Scotian Slope						
Exploration wells [3]						
Natural gas	**–**	**–**	–	–	1	1
Dry [4]	**–**	**–**	–	–	2	1
Suspended	**–**	**–**	1	1	–	–
Subtotal	**–**	**–**	1	1	3	2
Total North American Natural Gas	**675**	**517**	459	281	381	227
EAST COAST OIL						
Exploration wells [3]						
Oil	**–**	**–**	1	–	–	–
Dry [4]	**–**	**–**	2	1	1	–
Subtotal	**–**	**–**	3	1	1	–
Development wells [5]						
Oil	**17**	**4**	11	3	13	3
Natural gas	**–**	**–**	–	–	–	–
Dry	**–**	**–**	1	–	2	1
Subtotal	**17**	**4**	12	3	15	4
Total East Coast Oil	**17**	**4**	15	4	16	4
OIL SANDS						
Development wells [5]	**–**	**–**	–	–	–	–
Bitumen	**–**	**–**	–	–	–	–
Total Oil Sands	**–**	**–**	–	–	–	–

EXPLORATION AND DEVELOPMENT WELLS DRILLED

	2004		2003		2002	
	Gross [1]	**Net [2]**	Gross [1]	Net [2]	Gross [1]	Net [2]
INTERNATIONAL						
Exploration wells [3]						
Oil						
Northwest Europe	**–**	**–**	–	–	3	2
North Africa/Near East	**2**	**1**	1	–	–	–
Natural gas						
Northwest Europe	**–**	**–**	1	–	1	–
Northern Latin America	**1**	**–**	1	–	–	–
Dry [4]						
Northwest Europe	**4**	**1**	2	1	3	1
North Africa/Near East	**1**	**1**	–	–	1	1
Subtotal	**8**	**3**	5	1	8	4
Development wells [5]						
Oil						
Northwest Europe	**9**	**7**	7	4	5	3
North Africa/Near East	**45**	**16**	46	17	31	12
Natural gas						
Northwest Europe	**1**	**–**	1	–	–	–
Northern Latin America	**–**	**–**	3	1	4	1
Dry						
Northwest Europe	**1**	**–**	4	3	–	–
North Africa/Near East	**9**	**4**	5	2	5	2
Northern Latin America	**1**	**–**	1	–	–	–
Subtotal	**66**	**27**	67	27	45	18
Total International	**74**	**30**	72	28	53	22
Total wells drilled	**766**	**551**	546	313	450	253

1 Gross wells are wells, excluding all service wells, in which Petro-Canada owns a working interest. Gross wells include gross overriding royalty (GOR) wells.

2 Net wells are the sum of the fractional working interests owned by Petro-Canada in gross wells, rounded to the nearest whole number. Net wells exclude GOR wells.

3 Exploration wells are wells drilled to find and produce oil or natural gas in an unproved area, to find a new reservoir or to extend the known boundaries of a previously discovered reservoir.

4 A dry hole is an exploration or development well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

5 Development wells are wells drilled in an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Downstream

Business Summary and Strategy

Downstream operations include three refineries with a total rated capacity of 49,000 cubic metres per day (m^3/d) (308,000 b/d).[1] The Company's stand-alone lubricants plant is the largest producer of lubricant base stocks in Canada. In 2004, Petro-Canada accounted for about 15% of the Canadian industry's total refining capacity. Product sales represented about 17% of total petroleum products sold in Canada.

Downstream strategies are focused on strengthening the foundations for improved profitability through effective capital investment and discipline over controllable factors. The goal is superior returns and growth, including a 12% return on capital employed, based on a mid-cycle business environment. Key features of the strategy include:

- achieving and maintaining first quartile operating performance;
- advancing Petro-Canada as the "brand of choice" for Canadian gasoline consumers; and
- building on market strengths and increasing sales of high-margin specialty lubricants.

Refining and Supply

Petro-Canada owns and operates three refineries located in: Edmonton, Alberta; Montreal, Quebec; and Oakville, Ontario. With a total rated capacity of approximately 49,000 m^3/d in 2004, these refineries represent the second-largest refining capacity in Canada, with approximately 15% of the Canadian refining industry's total operating capacity. In 2004, Petro-Canada proceeded with its previously announced plans to consolidate the Eastern Canada refining operations at the Montreal refinery. This included the partial closure of the Oakville refining operations and a limited expansion of Montreal's refining capacity. In September 2004, the Company announced a decision to continue operating the Oakville refinery at a reduced capacity into 2005 in order to increase supply flexibility during the transition period. The completion of the Oakville closure in 2005 will result in a decrease in Petro-Canada's total refining capacity to approximately 12% of the Canadian refining industry's capacity. Petro-Canada has entered into third-party supply agreements that, when combined with the additional yield from Montreal, will replace the 9,500 m^3/d of light oil products currently produced at the Oakville refinery. Petro-Canada's refineries produce a full range of refined petroleum products, including gasolines, diesel oils, heating oils, aviation fuels, heavy fuel oils, asphalts, petrochemicals and feedstocks for lubricants.

In 2004, programs continued at both the Edmonton and Montreal refineries to enable Petro-Canada to meet federal regulatory requirements of lower limits for sulphur in gasoline and diesel by January 1, 2005 and June 1, 2006, respectively. The new gasoline desulphurization unit at the Edmonton refinery was completed and successfully commissioned in 2004. By year end, both the Edmonton and Montreal refineries were producing gasoline in compliance with new federal regulations well in advance of the January 1, 2005, deadline. Construction of the diesel desulphurization units are now under way at both Montreal and Edmonton refineries, with plans to be operational at both facilities well in advance of the legislated date.

The following table shows the daily rated capacity of Petro-Canada's refineries as at December 31, 2004 and the approximate average daily volumes of crude oil processed, including volumes processed by Petro-Canada for other companies for the years indicated. The overall utilization rate at the three refineries, adjusted for the partial closure of the Oakville refinery on November 12, 2004, averaged 98% in 2004.

[1] Capacity revised on a pro rata basis, from 49,800 m^3/d (313,000 b/d) in 2003 to reflect partial closure of Oakville refinery operations, effective November 12, 2004.

RATED CAPACITY OF REFINERIES AND AVERAGE DAILY CRUDE OIL PROCESSED

(thousands of m^3)

Refinery Location	Average Volumes of Crude Oil Processed/Calendar Day — Years Ended December 31, 2004	2003	2002	Daily Rated Capacity [1] As at December 31, 2004
Edmonton, Alberta	**19.6**	19.8	20.9	**19.9**
Montreal, Quebec	**16.0**	16.8	16.1	**16.7** [2]
Oakville, Ontario	**12.6**	13.3	13.4	**7.0** [3]
Total	**48.2**	49.9	50.4	**43.6**

1 Daily rated capacity is based on calendar days and definite specifications as to types of crude oil, the products to be obtained and the refinery processes required. Variations in these factors may result in actual capacity being higher or lower than rated capacities.

2 Excludes limited capacity expansion completed, but not rated, in December 2004. Total capacity will be restated once expanded capacity has been rated in 2005.

3 Capacity at the Oakville refinery was reduced by approximately 6,200 m^3/d, with the permanent closure of one of two crude processing trains on November 12, 2004. This was part of the previously announced consolidation of Eastern Canada refinery operations. Prior to such closure, daily rated capacity was 13,200 m^3/d.

Edmonton Refinery

The Edmonton refinery is Petro-Canada's largest and most efficient refinery, producing a high yield of light oils. The Edmonton refinery uses synthetic crude oil for up to 40% of its feedstock. Synthetic crude oil produces a higher yield of gasoline and middle distillates than conventional crude oil. The remainder of the refinery's feedstock is conventional light sweet and sour crude oil.

Under revised plans for upgrading and refining oil sands feedstock at the Edmonton refinery, Petro-Canada will build new crude and vacuum units, expand coker capacity and build additional sulphur capability. The new configuration, targeted for completion in 2008, will allow the refinery to directly upgrade 4,100 m^3/d of bitumen and process 7,600 m^3/d of sour synthetic crude oil, displacing the conventional crude that is refined today. The refinery will also continue to process sweet synthetic crude through its synthetic train. (Refer to the Oil Sands in the upstream section of this AIF, for long-term arrangement for the supply of bitumen and sour crude oil feedstocks to the Edmonton refinery on completion of the planned reconfiguration.)

Montreal Refinery

The Montreal refinery, supplied with imported crude oil primarily through the Portland-Montreal pipeline, has a flexible configuration allowing it to process a variety of crude oils, including heavy grades and intermediate feedstocks. The refinery produces gasolines, distillates, asphalts, petrochemicals, lubricant feedstocks and solvents.

A limited expansion of the refining and logistics handling capacity has been completed as part of the Eastern Canada refining and supply consolidation project. In the fourth quarter of 2004, the Montreal refinery began supplying up to 2,400 m^3/d of finished light oil product to the expanded Oakville terminal via the TNPI pipeline.

Oakville Refinery

The Oakville refinery is supplied with both domestic and imported crude oil through the Enbridge Inc. (Enbridge) pipeline system. A variety of domestic crude oil types are supplied through the Enbridge pipeline system. Since May 1999, offshore light crude oil is supplied via the Portland-Montreal pipeline, through Montreal and via the Enbridge Line 9. The refinery produces a wide range of products including gasolines, distillates and lubricant feedstocks for Petro-Canada's lubricants plant.

As part of the Eastern Canada refining and supply consolidation project, the Oakville refinery will complete a phased shutdown of its operations during the second quarter of 2005. Oakville's terminal facilities have been expanded to handle receipt of finished light oil product from Montreal via the TNPI pipeline. In total, the expanded Oakville terminal will receive up to 9,500 m^3/d of finished light oil product to replace what is currently produced by the Oakville refinery operations. In conjunction with the shutdown of the Oakville refinery, the asphalt operations adjacent to Petro-Canada's Mississauga lubricants facility were permanently closed in the fall of 2004.

Supply

Petro-Canada purchases crude oil and other refinery feedstocks from Canadian and international sources under a number of different contractual arrangements. The Downstream sector is responsible for arranging domestic and foreign crude supply for the Company's refineries. There is a well-developed infrastructure for third-party supply of both domestic and imported crudes to markets in North America. Purchases are generally through short-term, renewable contracts. Petro-Canada is not dependent on any single source of supply for conventional crude oil and does not anticipate any difficulty in obtaining an adequate supply in the foreseeable future.

Distribution

Petro-Canada operates an extensive distribution network, utilizing pipeline, road, rail and marine transportation, to deliver refined products to retail outlets and commercial and industrial customers. The Company holds interests in two refined product pipelines and a joint venture interest in one major refined products terminal. Petro-Canada also operates 11 major refined products terminals across Canada.

Distribution efficiencies are achieved through refined product exchange, purchase, sale and short-term storage arrangements with other petroleum companies. These arrangements reduce capital and transportation costs, assist in the maintenance of supply to customers and enable Petro-Canada to participate in geographical areas without the need to invest capital in distribution facilities. Applicable agreements contain appropriate provisions for consistent product quality to be maintained for the Company's customers.

Sales and Marketing

Petro-Canada is the second-largest marketer of petroleum products in Canada. In 2004, Petro-Canada's petroleum product sales represented approximately 17% of total petroleum products sold in Canada. Petro-Canada markets a full range of petroleum products, including gasolines, diesel oils, heating oils, aviation fuels, heavy fuel oils, asphalts, lubricants, petrochemical feedstocks and liquefied petroleum gases. Petro-Canada also generates non-petroleum revenue from convenience stores, car washes and automotive repair and maintenance services. During 2004, the Company focused on profitable growth through initiatives directed at the retail and PETRO-PASS truck stop networks.

The following table shows the approximate average daily volumes of petroleum products sold during the years indicated.

AVERAGE DAILY SALES OF PETROLEUM PRODUCTS
(thousands of m^3/d)

	Years Ended December 31,		
	2004	2003	2002
Gasoline [1]	**24.7**	25.8	25.9
Middle distillates [2]	**20.2**	20.5	19.3
Other [3]	**11.7**	10.5	10.5
Total	**56.6**	56.8	55.7

1 Includes motor and aviation gasolines.
2 Includes diesel oils, heating oils and aviation jet fuels.
3 Includes heavy fuel oils, asphalts, lubricants, liquefied petroleum gases, petrochemical feedstocks and other petroleum and non-petroleum products.

The following table shows the annual revenues derived from refining and marketing activities during the years indicated.

REFINING AND MARKETING REVENUES
(millions of dollars)

	Years Ended December 31,		
	2004	2003	2002
Gasoline [1]	**$4,218**	$3,726	$3,439
Middle distillates [2]	**3,262**	2,761	2,311
Other [3]	**1,953**	1,665	1,571
Total	**$9,434**	$8,152	$7,321

1 Includes motor and aviation gasolines.

2 Includes diesel oils, heating oils and aviation jet fuels.

3 Includes heavy fuel oils, asphalts, lubricants, liquefied petroleum gases, petrochemical feedstocks and other petroleum and non-petroleum products.

Retail

As at December 31, 2004, Petro-Canada's network of retail sites consisted of 1,375 outlets across Canada, of which 863 were Company-controlled and the balance were controlled by third parties. Independent dealers and agents operate virtually all of the outlets.

The Company continued to advance Petro-Canada's standing as the "brand of choice" through selective representation and site development, generating high site throughputs and a 17% share of the national market. In 2004, Petro-Canada led the industry in key urban market metrics and continued to improve the fundamentals of the business with more than 85% of the re-imaging program now complete. Fast-tracking this re-imaging program allowed the Company to realize industry-leading throughputs, with annual gasoline sales from re-imaged sites within Petro-Canada's network averaging more than 6.8 million litres per site. Based on this success, the Company extended this new image program to developments with independent retailers and more than 35% of these retailers have elected to invest their capital in the new image standard.

Petro-Canada continued to leverage its position as "Canada's Gas Station," with innovative product developments and new product firsts in the industry. In September 2004, the Company introduced the Citi Petro-Points MasterCard, the first general-purpose credit card in North America to offer cardholders an instant discount on gasoline. Petro-Canada accelerated the rollout of its Cash Point Program, the industry's first privately owned automated bank machine network. The Company also continued to focus on expanding its non-petroleum revenue base, as evidenced by the 11% year-over-year sales growth of its convenience store business and 7% increase in same-store sales in 2004 compared to 2003.

Wholesale and Refinery Sales

Petro-Canada sells petroleum products into the farm, home heating, paving, small industrial, commercial and truck markets. This category accounted for approximately 65% of total Downstream sales volumes. Petro-Canada is the leading national marketer to the commercial road transport segment in Canada with 213 PETRO-PASS sites. The Company also sells large volumes of petroleum products directly to large industrial and commercial customers and independent marketers. In 2004, asphalt total sales volume was approximately 1.4 billion litres.

The Company's focus has been on improving its sales mix and leveraging its best-in-class position in the commercial road transport and bulk fuels channels. In 2004, Petro-Canada expanded and upgraded the network and increased sales volume. In bulk fuels, the Company concentrated on integrating acquisitions in the home heat business.

Lubricants

The lubricants centre, located in Mississauga, Ontario, produces specialty lubricants and waxes that are marketed in Canada and internationally. Petro-Canada's lubricants plant is the largest producer of lubricant base stocks in Canada, with annual base oil production capacity in excess of 700 million litres.

The lubricants plant utilizes a two-stage hydro-treating process, which is unique in Canada. This process enables Petro-Canada to refine gas oils produced from a wide range of crude feedstocks into lubricating oil base stocks with the highest level of purity of any base stocks in Canada. Advancing lubricant technology and environmental concerns continue to increase the demand for high-purity, hydro-treated base stocks for many lubricant applications. Petro-Canada is well positioned to meet this growing demand.

The Company's strategy is to grow volume in high-margin sales and improve plant reliability. In 2004, Petro-Canada intensified efforts to optimize operations and maintenance procedures based on industry best practices. Lubricants sales in 2004 totaled 833 million litres, an increase of more than 8%, compared with sales volume of 768 million litres in 2003. This increase was achieved despite continued soft demand in the key U.S. export market. In 2004, the high-margin product component rose 11%, resulting in more than 67% of production going into high-margin markets. Lubricants continues to be well positioned for profitable future growth as tougher performance and environmental standards increase global demand for higher quality base oils and finished products.

Pipelines

Petro-Canada complements its production, extracting and refining operations with ownership in several crude oil and refined product pipelines. The principal pipelines in which the Company has an interest are the Alberta Products Pipe Line Inc., the TNPI pipeline and Montreal Pipe Line Limited.

Research and Development

Petro-Canada owns a research facility at Sheridan Park in Mississauga, Ontario, where the Company conducts research on lubricants. In 2004, Petro-Canada's expenditures on research and development activities were approximately $17 million.

As global advancements in fuel cell technology continue to occur, the Fuelling a Cleaner Canada Association (Petro-Canada, Ballard Power Systems and Methanex Company) has focused its efforts on working with various government agencies, such as the Canadian Transportation Fuel Cell Alliance (CTFCA), in an effort to ensure appropriate funding and the optimization of independent activities directed toward the implementation of fuel cell pilot demonstrations. In addition, through the CTFCA, knowledge from other pilot projects, such as the California Fuel Cell Partnership, can be shared, thereby assisting in the advancement of Canadian demonstrations.

Human Resources

As at December 31, 2004, Petro-Canada and its wholly owned subsidiaries had 4,788 employees, compared with 4,514 employees as at December 31, 2003. Of the year-end 2004 employees, 1,151 employees were employed in the upstream businesses, 322 employees were in International and 2,551 employees were in Downstream, with the remaining 764 employees being corporate support staff. Of the upstream employees, 173 employees were in East Coast Oil, 119 employees were in Oil Sands and 859 employees were in North American Natural Gas. One hundred and thirty-three of the upstream employees, 274 of the International employees, 16 of the Downstream employees and 13 of the corporate support staff employees were employed outside of Canada. Approximately 24% of Petro-Canada's employees were covered by collective bargaining agreements. Approximately 90% of the Company's unionized employees were members of the Communications Energy and Paperworkers Union (CEP) that represents refinery, marketing, gas plant and offshore production workers. Three-year collective bargaining agreements with most CEP locals will expire on January 31, 2007. Negotiations to reach a first agreement with employees on the Terra Nova FPSO are ongoing. Should the parties be unsuccessful in reaching a first agreement, an arbitrated settlement will be imposed.

Social and Environmental Policies

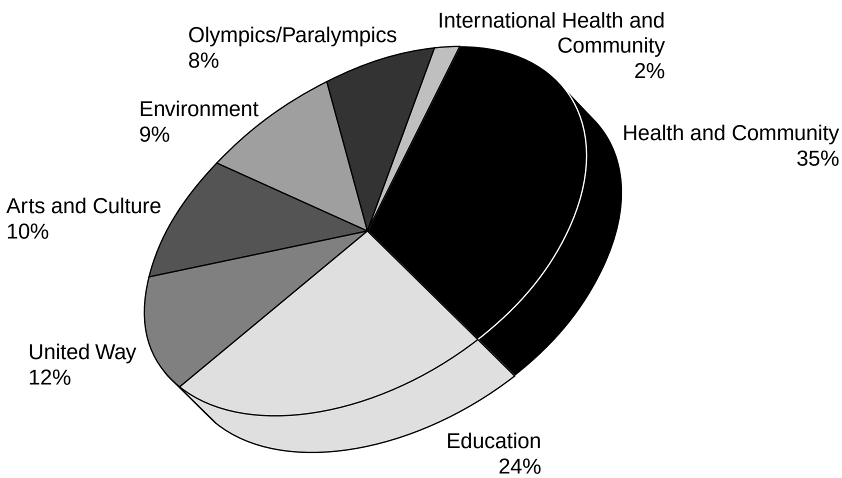
Petro-Canada is determined to earn the support received from stakeholders, not just through excellence in meeting customers' energy needs, but by playing an active and important role in the communities where the Company lives and operates. Petro-Canada conducts business in a highly principled manner, as guided by a Code of Business Conduct, corporate values and standards, and the values and standards of the societies that host Petro-Canada operations. Wherever the Company operates around the world, Petro-Canada aims to invest and conduct operations in a manner that is economically rewarding to all parties; recognized as being ethically, socially and environmentally responsible; welcomed by the communities in which Petro-Canada operates; and that facilitates economic, human and community development within a stable operating environment. Petro-Canada subscribes to the International Code of Ethics for Canadian Business, the United Nations Global Compact and the Universal Declaration of Human Rights.

Petro-Canada executives are accountable for the effective execution of TLM policy and standards. Petro-Canada conducts a major review of each business unit or area every four years to assess the implementation of the policy and standards. The executive leadership team reviews environment, health and safety performance monthly. As well, the Environment, Health and Safety Committee of the Board of Directors reviews environment, health and safety performance throughout the year.

At Petro-Canada, community investment is an integral part of the way the Company does business. Petro-Canada works with communities in key business locations to ensure the Company's presence generates value and makes a difference for neighbours.

The Company invests in initiatives that provide country-wide benefits, as well as grassroots programs and services at the local level. Petro-Canada funding is directed to areas reflecting community services, environment, and arts and culture.

CASH AND IN-KIND CONTRIBUTIONS OF NEARLY $7 MILLION IN 2004
(Unaudited, – Contribution in North America unless otherwise stated)



Highlights

- Employees in North America, along with the Company's Canadian retailers and wholesalers, raised more than $200,000 for the Red Cross Asian Disaster Relief effort. These contributions were matched by Petro-Canada. The International business contributed £10,000 to the London-based Disasters Emergency Committee.
- In 2004, Petro-Canada invested nearly $550,000 to support Canadian Olympic and Paralympic athletes and coaches through the Company's Olympic Torch Scholarships, Coaching Awards and athlete funding.
- Employees and the Company donated more than $2.1 million to United Way campaigns across North America in 2004.
- Through the Volunteer Energy Program, Petro-Canada provided 406 grants of $500 each to non-profit organizations supported by employees and retirees who give their time to the community. The total amount of grants provided since the program began in 1992 was more than $1.3 million by the end of 2004.

To learn more about Petro-Canada's corporate responsibility performance, please access the annual Report to the Community available at www.petro-canada.ca. The 2004 Report will be available in the second quarter of 2005.

Environmental Expenditures

In 2004, Petro-Canada's environmental capital and operating expenditures totaled $651 million, compared with $414 million in 2003 and $318 million in 2002. The increase in 2004 expenditures mainly reflected preparations to meet new federal regulations for sulphur limits in gasoline and diesel.

Environmental expenditures included: purchase, installation, operation and maintenance of pollution abatement equipment and facilities; replacement of underground tanks; waste management; environmental studies and research; reclamation activities; and the workforce costs of environmental staff and consultants.

The following table shows Petro-Canada's expenditures for environmental matters during 2004.

ENVIRONMENTAL COSTS – YEAR ENDED DECEMBER 31, 2004
(millions of dollars)

	Capital	Operating Expense	Total
Upstream	**$ 61**	**$ 66**	**$127**
Downstream	**479**	**45**	**524**
Total environmental costs	**$540**	**$111**	**$651**

More detailed information on the Company's policies and performance relative to the environment will be included in the annual Report to the Community available at www.petro-canada.ca. The 2004 Report will be available in the second quarter of 2005.

ITEM 6 – SELECTED CONSOLIDATED FINANCIAL INFORMATION

The following selected consolidated financial information for each of the three years in the period ended December 31, 2004, is derived from Petro-Canada's audited Consolidated Financial Statements. The information set forth below should be read in conjunction with Management's Discussion and Analysis, the Consolidated Financial Statements and related notes and other financial information.

SELECTED CONSOLIDATED FINANCIAL INFORMATION
(millions of dollars, except per share amounts)

	Years Ended December 31,		
	2004	2003	2002
Statement of earnings data			
Revenue			
Operating	**$14,687**	$ 12,887	$ 10,374
Investment and other income	**(310)**	12	–
Total revenue	**$14,377**	$ 12,899	$ 10,374
Earnings before income taxes	**$ 3,245**	$ 2,960	$ 1,798
Provision for income taxes	**1,488**	1,310	843
Net earnings	**$ 1,757**	$ 1,650	$ 955
Earnings			
North American Natural Gas	**$ 500**	$ 459	$ 169
East Coast Oil	**711**	597	428
Oil Sands	**120**	(52)	78
International	**372**	297	225
Downstream	**310**	263	249
Shared Services	**(125)**	(182)	(144)
Earnings from operations[1,2]	**1,888**	1,382	1,005
Foreign currency translation	**63**	239	(52)
Unrealized loss on Buzzard derivative contracts	**(205)**	–	–
Gain on asset sales	**11**	29	2
Net earnings	**$ 1,757**	$ 1,650	$ 955
Earnings per share – basic	**$ 6.64**	$ 6.23	$ 3.63
Earnings per share – diluted	**6.55**	6.16	3.59
Dividends per share	**0.60**	0.40	0.40
Cash flow from operating activities before changes in non-cash working capital[2]	**3,747**	3,372	2,276
Balance sheet data (at end of year)			
Total assets	**18,100**	14,774	13,544
Debt	**2,580**	2,229	3,057
Cash and cash equivalents	**170**	635	234
Shareholders' equity	**8,739**	7,588	5,662
Average capital employed	**$10,533**	$ 9,268	$ 7,722

1 Earnings from operations, which represents net earnings excluding gains or losses on foreign currency translation and on disposal of assets and the unrealized loss on Buzzard derivative contracts, is used by the Company to evaluate operating performance.

2 Earnings from operations and cash flow do not have any standardized meaning prescribed by Canadian GAAP and, therefore, may not be comparable with the calculation of similar measures for other companies.

QUARTERLY INFORMATION
(millions of dollars, except per share amounts)

	2004 Three Months Ended				2003 Three Months Ended			
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	Mar. 31	June 30	Sept. 30	Dec. 31
Total revenue	**$3,473**	**$3,565**	**$3,622**	**$3,717**	$3,722	$2,957	$3,118	$3,102
Earnings								
Upstream								
North American Natural Gas	**119**	**133**	**117**	**131**	163	142	91	63
East Coast Oil	**186**	**182**	**190**	**153**	162	157	139	139
Oil Sands	**34**	**25**	**51**	**10**	12	11	20	(95)
International	**123**	**72**	**93**	**84**	64	70	113	50
Downstream	**87**	**92**	**40**	**91**	130	126	(27)	34
Shared Services	**(32)**	**(33)**	**(30)**	**(30)**	(46)	(55)	(40)	(41)
Earnings from operations	**517**	**471**	**461**	**439**	485	451	296	150
Foreign currency translation	**(13)**	**(21)**	**54**	**43**	94	98	4	43
Unrealized loss on the Buzzard derivative contracts	**–**	**(57)**	**(107)**	**(41)**	–	–	–	–
Gain (loss) on sale of assets	**9**	**–**	**2**	**–**	–	35	(11)	5
Net earnings	**$ 513**	**$ 393**	**$ 410**	**$ 441**	$ 579	$ 584	$ 289	$ 198
Earnings per share								
Basic	**$ 1.93**	**$ 1.48**	**$ 1.54**	**$ 1.69**	$ 2.19	$ 2.20	$ 1.09	$ 0.75
Diluted	**$ 1.90**	**$ 1.46**	**$ 1.52**	**$ 1.67**	$ 2.16	$ 2.17	$ 1.08	$ 0.74

Dividends

From time to time, Petro-Canada reviews its dividend strategy to ensure the alignment of dividend policy with shareholder expectations and financial and growth objectives. Currently, the Company's first priority for available cash is to fund profitable growth opportunities. The second priority is to return funds to shareholders through dividends and share buyback programs. Commencing with the second quarter dividend paid on April 1, 2004, the Company increased the quarterly dividend 50% to $0.15 per share. Total dividends paid in 2004 were $159 million, compared with $106 million in 2003.

ITEM 7 – DESCRIPTION OF CAPITAL STRUCTURE

General Description of Capital Structure

The Company's authorized share capital is comprised of an unlimited number of common shares, an unlimited number of preferred shares issuable in series designated as senior preferred shares and an unlimited number of preferred shares issuable in series designated as junior preferred shares. As at December 31, 2004, there were 260,025,211 common shares issued and outstanding. To the knowledge of the Board of Directors and officers of Petro-Canada, no person beneficially owns or exercises control or direction over securities carrying 10% or more of the voting rights attached to any class of voting securities of the Company, except for Wellington Management Company LLP, which exercises control over 26,442,783 common shares, representing approximately 10.089% of the outstanding common shares. The holders of common shares are entitled to attend all meetings of shareholders and vote at any such meeting on the basis of one vote for each common share held. As no senior preferred shares or junior preferred shares are issued and outstanding, common share holders are entitled to receive any dividend declared by the Board of Directors on the common shares and upon a distribution of the Company's assets among its shareholders for the purpose of winding-up its affairs. The holders of the common shares shall be entitled to share equally, share for share, in all distributions of such assets.

Constraints

Ownership, Voting and Other Charter Restrictions

The *Petro-Canada Public Participation Act* requires that the Articles of Petro-Canada include certain restrictions on the ownership and voting of voting shares of the Company. The common shares of Petro-Canada are voting shares.

No person, together with associates of that person, may subscribe for, have transferred to that person, hold, beneficially own or control otherwise than by way of security only, or vote in the aggregate, voting shares of Petro-Canada to which are attached more than 20% of the votes attached to all outstanding voting shares of Petro-Canada.

As required by the *Petro-Canada Public Participation Act*, Petro-Canada's Articles contain provisions for the enforcement of these restrictions, including provisions for suspension of voting rights, forfeiture of dividends, prohibitions against share transfer, compulsory sale of shares, redemption and suspension of other shareholder rights. The Board of Directors may at any time require holders of or subscribers for voting shares and certain other persons to furnish statutory declarations as to ownership of voting shares and certain other matters relevant to the enforcement of the restrictions. Petro-Canada is prohibited from accepting any subscription for, issuing or registering a transfer of, any voting shares if a contravention of the individual ownership restrictions result.

Petro-Canada's Articles, as required by the *Petro-Canada Public Participation Act*, also include provisions requiring Petro-Canada to: maintain its head office in Calgary, Alberta; prohibit Petro-Canada from selling, transferring or otherwise disposing of all or substantially all of its assets in one transaction, or several related transactions, to any one person or group of associated persons or to non-residents, other than by way of security only in connection with the financing of Petro-Canada; and require Petro-Canada to ensure (and to adopt, from time to time, policies describing the manner in which Petro-Canada will fulfil the requirement to ensure) that any member of the public can, in either official language of Canada (English and French), communicate with and obtain available services from Petro-Canada's head office and any other facilities where Petro-Canada determines there is significant demand for communication with and services from that facility in that language.

Commercial Relationships

Petro-Canada has commercial relationships with various Canadian federal Crown Corporations which cover sales of product. Such relationships have been and will continue to be on the same terms as are available to third parties with similar requirements. With the 2004 sale by the Government of Canada of its shares in Petro-Canada, the government no longer has any direct ownership in the Company.

Ratings

The following table shows the ratings issued by the rating agencies noted therein as of December 31, 2004. A security rating is not a recommendation to buy, sell or hold securities and may be subject to revisions or withdrawal at any time by the rating agency.

PETRO-CANADA'S CREDIT RATINGS

	Moody's Investors Service Inc.	Standard & Poor's Rating Services	Dominion Bond Rating Service
Outlook	Stable	Stable	Stable
Senior Unsecured	Baa2	BBB	A (low)
Short-Term	–	–	R-1 (low)

ITEM 8 – MARKET FOR SECURITIES

Trading Price and Volume

The Company's outstanding share capital comprises common shares and each common share carries one vote. The Company's common shares trade on the TSX under the symbol PCA and on the New York Stock Exchange (NYSE) under the symbol PCZ.

The greatest volume of trading in the Company's shares takes place on the TSX. The following table sets out the trading range and volume traded on the TSX and the NYSE in 2004 on a monthly basis.

PETRO-CANADA SHARE TRADING ACTIVITY ON THE TORONTO STOCK EXCHANGE AND THE NEW YORK STOCK EXCHANGE IN 2004

	Toronto Stock Exchange				New York Stock Exchange			
	Share Price Trading Range (dollars per share)			Share Volume	Share Price Trading Range (U.S. dollars per share)			Share Volume
	High	Low	Close	(millions)	High	Low	Close	(millions)
2004								
January	$68.65	$57.82	$57.82	23.5	$52.81	$43.68	$43.68	1.5
February	60.55	56.51	60.32	27.2	45.63	42.37	45.08	1.2
March	61.10	55.85	57.62	24.1	45.95	41.90	43.85	1.9
April	61.89	57.80	60.62	19.7	45.79	43.89	44.22	1.1
May	64.16	58.81	60.15	16.6	46.73	43.07	43.30	1.2
June	59.60	56.65	57.65	20.4	44.15	41.78	43.20	1.0
July	62.45	56.40	62.05	19.2	47.05	42.63	46.91	1.2
August	62.30	59.72	61.50	16.3	47.50	45.33	46.77	1.0
September	67.24	61.40	65.74	36.7	52.20	47.60	51.95	8.4
October	69.49	65.29	66.48	28.8	55.85	52.10	54.49	4.1
November	67.79	62.50	67.79	25.3	57.10	52.42	57.10	3.5
December	66.94	60.60	61.17	30.5	56.50	48.80	51.02	3.3

Prior Sales

Petro-Canada and its wholly owned subsidiary, PC Financial Partnership, filed a shelf prospectus dated November 3, 2004 which provides the Company with the flexibility to issue up to $1 billion US of debt securities in the U.S. until December 2006. On November 8, 2004, PC Financial Partnership issued $400 million US of senior notes, leaving $600 million US available under the shelf prospectus. The following summarizes the details of this public offering:

Purpose of offering:	To repay bank indebtedness incurred in the acquisition of Prima Energy Corporation
Size of offering:	$400 million US
Maturity date:	November 15, 2014
Form of securities:	5.00% senior notes
Net proceeds of issue:	$394.3 million US
Public offering price:	99.472% per note
Application of proceeds:	Repay short-term, floating rate acquisition credit facility

ITEM 9 – ESCROWED SECURITIES

Not applicable.

ITEM 10 – DIRECTORS AND OFFICERS

Directors

The following describes information concerning Directors of the Company. Details regarding share ownership, the Deferred Share Unit (DSU) Plan and compensation of Directors can be found in the Company's Management Proxy Circular, dated March 3, 2005.

RON A. BRENNEMAN **Calgary, Alberta, Canada** Director since: 2000 Share ownership: 38,134 DSU ownership: 94,664	Ron Brenneman is the president and chief executive officer of the Company. Prior to joining the Company in 2000, he held various positions within Exxon Corporation (integrated oil) and its affiliated companies. He also serves as a director of the Bank of Nova Scotia and BCE Inc. He is a member of the Boards of Directors of the Canadian Council of Chief Executives and the Canadian Unity Council. Mr. Brenneman holds a BSc. and an MSc.
ANGUS A. BRUNEAU, O.C. **St. John's, Newfoundland and Labrador, Canada** Director since: 1996 Share ownership: 2,757 DSU ownership: 4,594	Angus Bruneau is chairman of the Board of Directors of Fortis Inc. (a utilities and services corporation). He also serves as a director of Inco Limited and SNC Lavalin Group Inc. He is an active executive member of a number of not-for-profit organizations, including Sustainable Development Technology Canada, Canadian Institute for Child Health, Canada's Top 40 Under 40, the Canadian Foundation for Innovation and the Nature Conservancy of Canada. Dr. Bruneau is a P.Eng and holds a BSc., D.Eng, and a PhD. He is chair of the Environment, Health and Safety Committee and a member of the Audit, Finance and Risk Committee.
GAIL COOK-BENNETT **Toronto, Ontario, Canada** Director since: 1991 Share ownership: 2,049 DSU ownership: 9,044	Gail Cook-Bennett is chairperson of the Canada Pension Plan Investment Board (public pension plan investment). She also serves as a director of Emera Inc. and Manulife Financial Corporation. Dr. Cook-Bennett holds a BA, MA, and a PhD (Econ). She is chair of the Pension Committee and a member of the Audit, Finance and Risk Committee.
RICHARD J. CURRIE, O.C. **Toronto, Ontario, Canada** Director since: 2003 Share ownership: 10,000 DSU ownership: 788	Dick Currie is chairman of the Board of Bell Canada Enterprises (BCE Inc.) (telecommunications). From 1996 to 2002, he had been president and director of George Weston Limited (food processing and distribution). He serves as a director of CAE, Inc. and Staples, Inc. He also serves as chancellor of the University of New Brunswick. Mr. Currie holds a BEng and an MBA. He is a member of the Management Resources and Compensation Committee and the Pension Committee.
CLAUDE FONTAINE, Q.C. **Montreal, Quebec, Canada** Director since: 1987 Share ownership: 10,407 DSU ownership: 12,776	Claude Fontaine is a senior partner with Ogilvy Renault (barristers and solicitors). He also serves as a director of Optimum General Inc., the Institute of Corporate Directors (national vice-chair and chair of the Quebec chapter) and the Montreal Heart Institute Foundation. He is an honourary governor of the Canadian Unity Council. Mr. Fontaine holds a BA and an LL. L. He is a member of the Management Resources and Compensation Committee and the Corporate Governance and Nominating Committee.
PAUL HASELDONCKX **Essen, Germany** Director since: 2002 Share ownership: 3,301 DSU ownership: 2,241	Paul Haseldonckx is the past chairman of the Executive Board of Veba Oil & Gas GmbH (integrated oil and gas) and its predecessor companies. He is a guest lecturer at Leiden University MBA Program on International Management. Mr. Haseldonckx holds an MSc. He is a member of the Audit, Finance and Risk Committee and the Environment, Health and Safety Committee.

THOMAS E. KIERANS, O.C. **Toronto, Ontario, Canada** Director since: 1991 Share ownership: 20,450 DSU ownership: 2,530	Tom Kierans is chairman of CSI Global Markets (financial education and accreditation), a for profit enterprise. Since 1999, he was consecutively executive chairman and chairman of the Canadian Institute for Advanced Research. He also serves as a director of Manulife Financial Corporation and BCE Inc. He is an advisor to Lazard Corporation (Canada), York University and The University of Western Ontario. He holds a BA (Honours) and an MBA (Finance, Dean's Honours List) and is a fellow of the (Canadian) Institute of Corporate Directors. He is chair of the Management Resources and Compensation Committee and a member of the Corporate Governance and Nominating Committee.
BRIAN F. MACNEILL **Calgary, Alberta, Canada** Director since: 1995 Share ownership: 5,100 DSU ownership: 15,842	Brian MacNeill is the chairman of the Board of Directors of Petro-Canada. Prior to that, he was president and chief executive officer of Enbridge Inc. (pipeline business). He is also chairman and director of Dofasco Inc. and a director of the Toronto-Dominion Bank, West Fraser Timber Co. Ltd. and TELUS Corporation. He is a member of the Alberta and Ontario Institutes of Chartered Accountants and the Financial Executives Institute. He is a fellow of the Canadian Institute of Chartered Accountants and chair of the Board of Governors of the University of Calgary. Mr. MacNeill is a CPA and holds a B.Comm. He is a member of all committees of the Board of Directors of the Company.
MAUREEN McCAW **Edmonton, Alberta, Canada** Director since: 2004 Share ownership: 494 DSU ownership: 550	Maureen McCaw is president of Criterion Research Corp. (marketing research), having founded the company in 1986. She is the immediate past chair of the Edmonton Chamber of Commerce and continues to serve as a director thereof. She also serves on a number of Alberta boards and advisory committees. Ms. McCaw holds a BA. She is a member of the Environment, Health and Safety Committee and the Pension Committee.
PAUL D. MELNUK **St. Louis, Missouri, USA** Director since: 2000 Share ownership: 2,200 DSU ownership: 5,897	Paul Melnuk is chairman and chief executive officer of Thermadyne Holdings Corporation (industrial products) and managing partner of FTL Capital Partners LLC (merchant banking). Prior to that he was chairman of the Board of Directors of Thermadyne Holdings Corporation. He is past president and chief executive officer of Bracknell Corporation and Barrick Gold Corporation. He is a member of the Canadian Institute of Chartered Accountants and of the World Presidents' Organization, St. Louis chapter. Mr. Melnuk holds a B.Comm and is chair of the Audit, Finance and Risk Committee and a member of the Environment, Health and Safety Committee.
GUYLAINE SAUCIER, F.C.A., C.M. **Montreal, Quebec, Canada** Director since: 1991 Share ownership: 4,260 DSU ownership: 13,788	Guylaine Saucier is past chair of each of the Joint Committee on Corporate Governance, the Canadian Broadcasting Corporation and the Canadian Institute of Chartered Accountants. She is a director of Altran Technologies, the Bank of Montreal, Nortel Networks Corporation, AXA Assurances Inc. and CHC Helicopter Corp. Mrs. Saucier holds a BA and a B.Comm and is a fellow of the Canadian Institute of Chartered Accountants. She is chair of the Corporate Governance and Nominating Committee and a member of the Pension Committee.
JAMES W. SIMPSON **Danville, California, USA** Director since: 2004 DSU ownership: 413	Jim Simpson is past president of Chevron Canada Resources (oil and gas). He is also the past chairman of the Canadian Association of Petroleum Producers and vice-chairman of the Canadian Association of the World Petroleum Congresses. Mr. Simpson holds a BSc. and a MSc. and is a member of the Audit, Finance and Risk Committee and the Environment, Health and Safety Committee.

The term of office for each of the Directors named above ends at the close of the next annual meeting of the shareholders' of the Company, or until his or her successor is elected or appointed.

Officers

The following table shows certain information concerning officers of the Company.

Name and Municipality of Residence	Served as an Officer Since	Principal Occupation [1]
Brian F. MacNeill Calgary, Alberta	2000	Chairman of the Board of the Company
Executive Leadership Team		
Ron A. Brenneman Calgary, Alberta	2000	President and Chief Executive Officer of the Company
Peter S. Kallos London, England	2003	Executive Vice-President, International
Boris J. Jackman Mississauga, Ontario	1993	Executive Vice-President, Downstream
E. F. H. Roberts Calgary, Alberta	1989	Executive Vice-President and Chief Financial Officer
Brant G. Sangster Calgary, Alberta	1988	Senior Vice-President, Oil Sands
Kathleen E. Sendall Calgary, Alberta	1996	Senior Vice-President, North American Natural Gas
Gordon J. Carrick St. John's, Newfoundland and Labrador	2002	Vice-President, East Coast
Upstream		
Youssef Ghoniem Dorsten, Germany	2002	Senior Vice-President, Operations
Nicholas A. Maden London, England	2003	Vice-President, International and Offshore Exploration
Gerhard Kinast London, England	2002	Vice-President, Finance
Graham Lyon London, England	2004	Vice-President, Business Development, International
Donald M. Clague Denver, Colorado	2002	Vice-President, U.S. Operations, North American Natural Gas
Francois Langlois Calgary, Alberta	2002	Vice-President, Exploration, North American Natural Gas
John D. Miller Calgary, Alberta	2004	Vice-President, Natural Gas Marketing
Leon Sorenson Calgary, Alberta	2004	Vice-President, Canadian Operations, North American Natural Gas
Downstream		
Randall B. Koenig Oakville, Ontario	1996	Vice-President, Lubricants

Name and Municipality of Residence	Served as an Officer Since	Principal Occupation [1]
S. Ford Ralph Erin, Ontario	1985	Vice-President, Wholesale/Retail
Frederick Scharf Mississauga, Ontario	2003	Vice-President, Marketing
Daniel P. Sorochan Mississauga, Ontario	2003	Vice-President, Refining and Supply
Shared Services		
Andrew Stephens [2] Calgary, Alberta	1993	Vice-President, Corporate Planning and Communications
W. A. (Alf) Peneycad [2] Calgary, Alberta	1986	Vice-President, General Counsel and Chief Compliance Officer
M. A. (Greta) Raymond [2] Calgary, Alberta	2001	Vice-President, Human Resources and Environment, Health, Safety and Security, and Chief Privacy Officer
Hugh L. Hooker Calgary, Alberta	2004	Associate General Counsel and Corporate Secretary
Douglas S. Fraser Calgary, Alberta	2002	Treasurer
Christopher J. Smith Calgary, Alberta	1989	Controller
Michael Danyluk Calgary, Alberta	2004	Chief Information Officer

1 Each of the officers has been engaged in the principal occupation indicated above or in executive positions with Petro-Canada for the five preceding years except for Ron A. Brenneman who, prior to January 2000, was general manager of Corporate Planning, Exxon Corporation, and prior thereto held various positions within Exxon and its affiliated companies; Brian F. MacNeill who, prior to 2001, was president and chief executive officer of Enbridge Inc.; Donald M. Clague who, prior to 2002, was manager, Exploration East Coast/Offshore, and prior thereto chief geophysicist; Douglas S. Fraser who, prior to 2002, was senior director, Downstream Accounting and Control; and Francois Langlois who, prior to 2002, was manager, Southern Exploration, and prior thereto general manager, North Africa and prior thereto team leader, Foothills Exploration; Peter S. Kallos who, prior to 2003, was vice-president, Corporate Planning and Communications, and prior thereto was external affairs director of Shell Exploration and Production U.K., and prior thereto was general manager of Enterprise's U.K. Business Unit, and prior thereto was chief executive officer of Enterprise's Italian subsidiary; Nicholas Maden who, prior to 2003, was exploration manager, International business unit, and prior thereto was business development manager with Veba Oil & Gas GmbH, and prior thereto held various exploration management positions with ARCO; Frederick Scharf who, prior to 2003, was general manager, Western Canada Wholesale/Retail; and Daniel Sorochan who, prior to 2003, was senior director of Business Development, Refining and Supply, and prior thereto was general manager, Oakville refinery; Leon Sorenson who, prior to 2004, was manager of Production Engineering and Operations, Western Canada Productions, and prior thereto was manager of Northern Development, Western Canada Development and Operations, and prior thereto was manager of Engineering Technology; Graham Lyon who, prior to 2004, was senior director, Business Development and prior thereto was head of Business Development, Deminex UK Oil & Gas; Michael Danyluk who, prior to 2004, was senior director of Information Systems; John Miller who, prior to 2004, was general manager of Gas Marketing, and prior thereto was manager of Gas Marketing, and prior thereto was manager, Oil Sands Infrastructure, and prior thereto was portfolio manager, Oil Sands Business Integration, and prior thereto was portfolio manager, Natural Gas Marketing; and Hugh Hooker who, prior to 2004, was associate general counsel.

2 Associate member of the executive leadership team.

Additional Disclosure Relating to Directors

To the knowledge of Petro-Canada, no director of Petro-Canada is, or has been in the last ten years, a director or executive officer of an issuer that, while that person was acting in that capacity, (a) was the subject of a cease trade order or similar order or an order that denied the issuer access to any exemptions under Canadian securities legislation, for a period of more than 30 consecutive days, (b) was subject to an event that resulted, after that person ceased to be a director or executive officer, in the issuer being the subject of a cease trade or similar order or an order that denied the issuer access to any exemption under Canadian securities legislation, for a period of more than 30 consecutive days, or (c) or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets except for the following:

(i) Mme. Saucier, who is subject to a cease trade order in her capacity as a director of Nortel Networks Corporation. On May 31, 2004, the Ontario Securities Commission (OSC) issued a final management cease trade order (CTO) prohibiting certain directors, senior officers and certain current and former employees of Nortel Networks Corporation and Nortel Networks Limited from trading in the securities of Nortel Networks Corporation and Nortel Networks Limited, which finalized the temporary order issued on May 17, 2004. This final order will remain in effect until two full business days following the receipt by the OSC of all filings required to be made by Nortel Networks Corporation and Nortel Networks Limited pursuant to Ontario securities laws. Securities commissions in certain other provinces have issued similar final orders with respect to certain insiders of Nortel Networks Corporation and Nortel Networks Limited who are residents in those jurisdictions.

(ii) Messrs. Currie and Kierans were directors of Teleglobe Inc. from December 2000 until April 2002. Teleglobe Inc. filed for court protection under insolvency statutes on May 28, 2002.

Corporate Governance Practices

Principles

As an international and publicly traded oil and gas company, Petro-Canada recognizes the importance of adhering to superior corporate governance standards. The Company has developed sound corporate governance policies and procedures, which are monitored and reviewed on a continuous basis, and adopts a "best practices" approach in all of its corporate governance initiatives. The Company's Board of Directors, management and employees believe that strong corporate governance is essential to the creation of shareholder value and maintaining the confidence of investors. The Corporate Governance and Nominating Committee is responsible for monitoring the development of, and compliance with, corporate governance policies and procedures.

Board of Directors

The Board of Directors is responsible for overseeing the management of Petro-Canada's business and affairs. The Board of Directors has the statutory authority and obligation to act in good faith, with a view to protect and enhance the value of the Company, in the interest of all shareholders. To this end, members of the Board of Directors are expected to exercise independent judgment with the utmost honesty and integrity, adhering to all Company policies and procedures, legal requirements and regulatory regimes.

Composition of the Board of Directors

The Articles of the Company require the Board of Directors to be comprised of a minimum of nine and a maximum of 13 directors. The number of Directors may be increased or decreased by resolution of the Board of Directors within the minimum and maximum numbers set forth in the Articles.

The Company's shareholders elect the Board of Directors at the Annual Meeting each year. The Corporate Governance and Nominating Committee is responsible for recommending Director nominees to the Board of Directors, having regard to the competencies and skills required by the Board of Directors and the competencies and skills that potential nominees would bring to the Board of Directors, if elected.

Independence of the Board of Directors

Independence of the Board of Directors is essential to fulfilling its role in overseeing the Company's business and affairs. All but one of the current Directors are "unrelated" under the TSX Corporate Governance Guidelines and "independent" under Proposed National Instrument 58-101 (NI 58-101), the NYSE Corporate Governance Standards and the *Sarbanes-Oxley Act of 2002 (SOX)*.[1] Ron A. Brenneman, Petro-Canada's president and chief executive officer, is not unrelated or independent. The Board of Directors has determined that no other Director is in a relationship with the Company that would preclude such Director's status as unrelated or independent under the foregoing rules and policies. To further the Company's aim to maintain Director independence, the Board of Directors holds *in camera* sessions during each Directors' meeting without management present.

Responsibilities of the Board of Directors

The Board of Directors oversees the management of Petro-Canada's business and affairs, which is done through the day-to-day management of the Company by the president and chief executive officer and the executive leadership team. The principal duties of the Board of Directors include the following:

- managing its own affairs, including planning its composition, selecting its chair, appointing committees and their chairs, establishing Board of Directors and committee procedures, and determining Director compensation;
- determining the selection, retention, succession and compensation of senior management;
- conducting an annual performance evaluation of the president and chief executive officer and establishing a list of special objectives for the ensuing year;
- reviewing and approving the mission of Petro-Canada's business, its objectives and goals, and the strategy for their achievement;
- monitoring the Company's progress toward its goals, and taking action to fulfill those goals;
- approving and monitoring compliance with all significant policies and procedures by which the Company is operated;
- reviewing and approving the financial statements, business plan and capital budget of the Company;
- overseeing the accurate and timely reporting to shareholders and regulators of the Company's performance, financial statements and significant developments; and
- approving any significant new venture that is outside the Company's ordinary course of business, any expenditure not included in the annual budget approved by the Board of Directors and any transaction with a value in excess of $75 million.

Review of the Board of Directors

The chair of the Board of Directors provides leadership with regard to the work of the committees of the Board of Directors and the effective performance of the Board of Directors, including a process for evaluation of the performance of the Board of Directors. Each year, the chairs of the Management Resources and Compensation Committee and the Corporate Governance and Nominating Committee, in consultation with other members of the Board of Directors, review the performance of the chair of the Board of Directors and set objectives for the coming year. The Corporate Governance and Nominating Committee leads an annual process to evaluate the Board of Directors, and the Board of Directors informally reviews its own performance at the end of each Board of Directors meeting. Individual Directors complete an annual self-assessment, which is reviewed by the chair of the Corporate Governance and Nominating Committee and discussed with the Board of Directors.

Committees of the Board of Directors

The Board of Directors currently has the following five standing committees:

- Audit, Finance and Risk Committee;
- Corporate Governance and Nominating Committee;
- Management Resources and Compensation Committee;
- Pension Committee; and
- Environment, Health and Safety Committee.

Each committee typically has at least five members, each of whom are "unrelated" under the TSX Corporate Governance Guidelines, and "independent" under NI 58-101, the NYSE Corporate Governance Standards and SOX. Ron A. Brenneman, Petro-Canada's president and chief executive officer, is not a member of any of the committees; he is invited to attend all committee meetings, except the *in camera* portions.

---

[1] Further detail regarding these regulations can be found in this AIF under "Legislative and Regulatory Requirements" and in the Company's Management Proxy Circular, dated March 3, 2005 as well as on the Web site at www.petro-canada.ca.

Each committee undertakes detailed examinations of specific aspects of the Company. Committee meetings provide a smaller, more intimate forum than full Board of Directors meetings and are designed to be more conducive to exhaustive and forthright discussion. The chair of each committee provides a report to the Board of Directors following each committee meeting.

For additional detail regarding the Board of Directors committees, please refer to Guideline 9 in the Management Proxy Circular, dated March 3, 2005, detailing the Company's compliance with the TSX Corporate Governance Guidelines. In addition, each committee's Terms of Reference can be found on the Company's Web site at www.petro-canada.ca.

For additional detail concerning the Audit Finance and Risk Committee, please refer to the Audit Committee Disclosure section of this AIF.

Legislative and Regulatory Requirements

The Board of Directors must act in accordance with the Company's Articles and By-Laws, the *Petro-Canada Public Participation Act*, the *Canada Business Corporations Act*, and securities, environmental and other relevant legislation.

Canada*: NI 58-101, Proposed National Policy 58-201 (NP 58-201) and the TSX Corporate Governance Guidelines*

In Canada, Petro-Canada's shares are listed on the TSX. The TSX requires each listed company to annually discuss its approach to corporate governance. Petro-Canada's disclosure must refer to each of the TSX Corporate Governance Guidelines and, where the Company's approach is different from any of those guidelines or where the guidelines do not apply, must explain the differences or their inapplicability. In addition, the Canadian securities regulators have proposed NI 58-101 and NP 58-201, which also provides for detailed corporate governance guidelines and disclosure requirements. It is anticipated that NI 58-101 and NP 58-201 will be adopted and apply to fiscal years ending on or after June 30, 2005.

Although listed companies are not yet required to provide corporate governance disclosure pursuant to NI 58-101, Petro-Canada has provided this disclosure on the Company's Web site at www.petro-canada.ca. The Company's existing corporate governance practices comply with the TSX Corporate Governance Guidelines.

United States*: NYSE Corporate Governance Standards and SOX*

In the U.S., Petro-Canada's shares are listed on the NYSE. As a foreign private issuer in the U.S., Petro-Canada is not required to comply with most of the NYSE Corporate Governance Standards. However, the Company is required to disclose the significant differences between its corporate governance practices and the requirements applicable to U.S. domestic issuers listed on the NYSE. In addition, as of July 31, 2005, Petro-Canada is required to comply with certain audit committee requirements set out in the NYSE Corporate Governance Standards.

Petro-Canada is substantially in compliance with the current NYSE Corporate Governance Listing Standards and audit committee requirements. There are no significant differences between Petro-Canada's corporate governance practices and those required of U.S. domestic issuers under the NYSE Listing Standards. Petro-Canada has continued to adjust its practices to reflect the requirements of the NYSE Listing Standards and SOX. This includes commencing the process of revising the written mandates for the Board of Directors and the Board committees to provide for additional detail as to their purpose, responsibilities and procedures. In addition, the Company has instituted a whistleblower hotline for employees to anonymously report matters to the chief compliance officer and chair of the Audit, Finance and Risk Committee. Petro-Canada has a Code of Business Conduct applicable to all Directors, officers and employees and a Code of Ethics for its senior financial officers.

Additional detail regarding Petro-Canada's alignment with the NYSE Corporate Governance Listing Standards and compliance with SOX can be found on the Company's Web site at www.petro-canada.ca.

Audit Committee Disclosure

The following reviews certain information regarding the Company's Audit, Finance and Risk Committee, as required pursuant to Multilateral Instrument 58-101.

Audit, Finance and Risk Committee

Chair: Paul D. Melnuk
Members: Angus A. Bruneau, Gail Cook-Bennett, Paul Haseldonckx, James W. Simpson, Brian F. MacNeill
2004 Committee Meetings: nine

This Committee is composed entirely of independent Directors, each of whom are financially literate. Details as to each committee member's education and experience that provide the member with the necessary knowledge and understanding of accounting principles and procedures can be found above under "Directors." The Committee is responsible for reviewing and providing recommendations to the Board of Directors regarding the Company's accounting policies, reporting practices, internal controls, the Company's annual and interim financial statements, financial information included in the Company's disclosure documents, risk management matters, and oil and gas reserves booking and reporting. The Committee also reviews significant audit findings, material litigation and claims, and any issues between management and the auditors. The Committee maintains direct relationships with the Company's contract internal auditor and external auditor. The Committee meets *in camera* with both the contract internal auditors and external auditors at least once per year. The Committee is responsible for recommending the appointment and compensation of the external auditors. The Committee has a policy in place that non-audit work may not be performed by the external auditor. The Terms of Reference of the Audit, Finance and Risk Committee are attached to this AIF as Schedule "C" and can also be found on the Company's Web site at www.petro-canada.ca.

Audit Fees

Deloitte & Touche LLP were appointed as auditors of the Company on June 7, 2002. Deloitte & Touche LLP billed the Company for services rendered in the year ended December 31, 2004, as follows: (a) audit fees – $2,367,000 (2003 – $2,201,000), (b) audit-related services for a pension plan and attest services – $71,000 (2003 – $28,000) and (c) other services related to the licensing of access to industry databases – $107,000 (2003 – $74,000).

The Board of Directors adheres to a practice of limiting the auditors from providing services not related to the audit. In 2004, the Company cancelled the licensing of access to industry databases provided by the auditors. All services provided by the auditors are pre-approved by the Audit, Finance and Risk Committee.

Share Ownership

As at December 31, 2004, the Directors and officers of Petro-Canada, as a group, beneficially owned or exercised control over 144,580 common shares or less than 1% of the common shares of the Company outstanding as of such date.

ITEM 11 – PROMOTERS

Not applicable.

ITEM 12 – LEGAL PROCEEDINGS

Petro-Canada is not named as the defendant to any proceedings that involve a liability of a material amount.

ITEM 13 – INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No Director, executive officer or principal shareholder of Petro-Canada, or associate or affiliate of those persons, has any material interest, direct or indirect, in any transaction within the last three years that has materially affected or will materially affect Petro-Canada.

ITEM 14 – TRANSFER AGENTS AND REGISTRARS

In Canada:
CIBC Mellon Trust Company
600 The Dome Tower,
333 - 7 Avenue S.W.
Calgary, Alberta T2P 2Z1
Tel: 1-800-387-0825
Web site: www.cibcmellon.com

In the U.S.:
Mellon Investor Services
44 Wall Street, 6 Floor
New York, New York
10005
Tel: 1-800-387-0825
Web site: www.cibcmellon.com

ITEM 15 – MATERIAL CONTRACTS

Petro-Canada has not entered into any material contracts, outside the ordinary course of business, within two years before the date of this AIF.

ITEM 16 – INTERESTS OF EXPERTS

Deloitte & Touche LLP are the Company's auditors and such firm has prepared an opinion with respect to the Company's Consolidated Financial Statements as at and for the fiscal year ended December 31, 2004. Kathleen Sendall is a senior vice-president with the Company and has certified a report with respect to NI 51-101 oil and gas reserves disclosure. Neither party holds more than 1% of the Company's outstanding securities; in particular, Deloitte & Touche LLP has advised that it holds none of the Company's outstanding securities.

ITEM 17 – ADDITIONAL INFORMATION

Financial information is provided in the Company's Consolidated Financial Statements and MD&A for its most recently completed financial year. Additional information, including Directors' and officers' remuneration and indebtedness of principal holders of the Company's securities and securities authorized for issuance under equity compensation plans is contained in the Company's Management Proxy Circular, dated March 3, 2005.

Copies of this AIF, as well as the Company's latest Management Proxy Circular and Annual Report (which includes the Company's Consolidated Financial Statements and MD&A) for the year ended December 31, 2004, may be obtained from the Company's Web site at www.petro-canada.ca or by mail upon request from the corporate secretary, 150 - 6th Avenue S.W., Calgary, Alberta, T2P 3E3.

You may also access disclosure documents and any reports, statements or other information that Petro-Canada files with the Canadian provincial securities commissions or other similar regulatory authorities through the Internet on the Canadian System for Electronic Document Analysis and Retrieval, which is commonly known by the acronym SEDAR, and which may be accessed at www.sedar.com. SEDAR is the Canadian equivalent of the U.S. SEC's Electronic Document Gathering and Retrieval System, which is commonly known by the acronym EDGAR, and which may be accessed at www.sec.gov.

SCHEDULE A

REPORT ON RESERVES DATA
BY
SENIOR OFFICER RESPONSIBLE FOR RESERVES DATA

To the Board of Directors of Petro-Canada (the Company):

1. The Company's staff of qualified reserves evaluators have evaluated the Company's reserves data as at December 31, 2004. The reserves data consist of the following:

   (i) proved oil and gas reserves quantities estimated as at December 31, 2004, using constant prices and costs; and

   (ii) the Standardized Measure of Discounted Future Net Cash Flows relating to proved oil and gas reserves quantities.

2. The reserves data are the responsibility of the Company's management. As the member of the executive responsible for the Company's hydrocarbon reserves data, my responsibility is to certify that the reserves data has been properly calculated in accordance with industry generally accepted procedures for the estimation of reserves data.

3. The Company's reserves staff and management carried out their evaluations in accordance with industry generally accepted procedures for the estimation of reserves data and standards as 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) with the necessary modifications to reflect the definition of proved reserves under the applicable U.S. Financial Accounting Standards Board of Directors policies (the FASB Standards) and the legal requirements of the U.S. Securities and Exchange Commission (SEC Requirements). The Company's reserves staff and management are not independent of the Company, within the meaning of the term "independent" under those standards.

4. The standards require that they 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 developed in accordance with the evaluation practices and procedures presented in the COGE Handbook as modified to meet the requirements of the FASB Standards and SEC Requirements.

5. The following sets forth the standardized measure of future net cash flows attributed to proved oil and gas reserve quantities, estimated using constant prices and costs and calculated using a discount rate of 10%, included in the reserves data of the Company evaluated for the year ended December 31, 2004:

STANDARDIZED MEASURE OF FUTURE NET CASH FLOWS – PROVED OIL AND GAS RESERVES
(10% discount rate)
As at December 31, 2004

Location of Reserves (by business)	Standardized Measure (After Deducting Income Taxes)
	(millions of dollars)
North American Natural Gas	3,729
East Coast Oil	1,042
Northwest Europe	1,823
North Africa/Near East	725
Northern Latin America	213
Syncrude Oil Sands Mining Operation	1,597

The Standardized Measure values above were calculated consistent with the methodology prescribed in Financial Accounting Standards Board Statement No. 69.

6. In my opinion, the reserves data evaluated by the Company's reserves evaluation staff and management have, in all material respects, been determined in accordance with evaluation practices and procedures presented in the COGE Handbook with the necessary modifications to reflect reserves definitions and legal requirements under the applicable FASB Standards and SEC Requirements.

7. The reservoir engineering staff and management review and evaluate the reserves data on an ongoing basis and advise the executive of the Company of significant changes to the evaluations for events and circumstances occurring after the effective date of this report.

8. Reserves are estimates only, and not exact quantities. In addition, the reserves data are based on judgments regarding future events; actual results will vary and the variations may be material.

/Signed/

Kathleen E. Sendall, Senior Vice-President, North American Natural Gas
Member of Executive Leadership Team Responsible for Reserves

Dated March 15, 2005

SCHEDULE B

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

The management of Petro-Canada (the Company) is responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

(i) proved oil and gas reserves quantities estimated as at December 31, 2004, using constant prices and costs; and

(ii) the Standardized Measure of Discounted Future Net Cash Flows relating to proved oil and gas reserves quantities.

Our reserves evaluation process involves applying generally accepted practices and procedures for the estimation of reserves data as set out in the COGE Handbook and modified to reflect the definitions and standards as set out in the applicable provisions of the U.S. Financial Accounting Standards Board Statement of Financial Accounting Standards No. 69 and the relevant legal requirements of the U.S. Securities and Exchange Commission (SEC), (collectively the Reserves Data Process). Our qualified internal reserves evaluation staff and management have evaluated our reserves and the executive member responsible for reserves data certifies that the Reserves Data Process has been followed. The report of the executive member responsible for reserves data will be filed with securities regulatory authorities concurrently with this report.

The Company has designated the Audit, Finance and Risk Committee of its Board of Directors as performing the roles and responsibilities of the Reserves Committee of the Board of Directors as set out in National Instrument 51-101. The Audit, Finance and Risk Committee of the Board of Directors has:

(a) reviewed the Company's procedures for providing information to the internal and external qualified reserves evaluators;

(b) met with the internal and external qualified reserves evaluators to determine whether any restrictions placed by management affect the ability of the internal and external qualified reserves evaluators to report without reservation; and

(c) reviewed the reserves data with reserves management and each of the qualified external reserves evaluators.

The Audit, Finance and Risk 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 Audit, Finance and Risk Committee, approved:

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

(b) the filing of the report of the executive member responsible for reserves on the reserves data; and

(c) the content and filing of this report.

The Company has sought from, and was granted by, securities regulatory authorities an exemption from the requirement under securities legislation to involve independent qualified reserves evaluators or independent qualified reserves auditors. Notwithstanding this exemption, the Company involves independent qualified reserve evaluators or auditors as part of its corporate governance practices. In 2003, the independent evaluators/auditors evaluated, audited and/or reviewed nearly 90% of the Company's proved reserves data by volume. Their involvement helps assure that our internal reserves data are materially correct.

In our view, the reliability of the internally generated reserves data is not materially less than would be afforded by our involving independent qualified reserves evaluators or independent qualified reserves auditors to evaluate, audit and/or review the reserves data. Our reserves data is international in nature. Our securities regulatory reporting is as an SEC registrant and, therefore our reserves data is developed in accordance with practices and procedures set out in the Canadian Oil and Gas Evaluation Handbook and modified to meet the applicable U.S. Financial Accounting Standards Board and SEC reserves definitions, and the legal requirements of the SEC. Our procedures, records and controls relating to the accumulation of source data and preparation of reserves data by our internal reserves evaluation staff have been established, refined and documented over many years. Our internal reserves evaluation staff and management includes 71 persons with an average of more than 10 years of relevant experience in evaluating reserves, of whom 37 are qualified reserves evaluators for purposes of Canadian securities regulatory requirements. Our internal reserves evaluation management personnel includes nine persons with an average of 19 years of relevant experience in evaluating and managing the evaluation of reserves.

Reserves data are estimates only, and are not exact quantities. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

/Signed/

Ron A. Brenneman, President and Chief Executive Officer

/Signed/

Kathleen E. Sendall, Senior Vice-President, North American Natural Gas

/Signed/

Paul D. Melnuk, Director

/Signed/

Brian F. MacNeill, Director

Dated March 15, 2005

SCHEDULE C

AUDIT, FINANCE AND RISK COMMITTEE

1. TERMS OF REFERENCE

The duties and responsibilities of the Audit, Finance and Risk Committee shall include the following:

(a) assist the Board of Directors in the discharge of its fiduciary responsibilities relating to the Company's accounting policies, reporting practices and internal controls, as well as to its risk management policies and practices;

(b) maintain a direct line of communications with the chief financial officer and with the contract auditor and the external auditors, and monitor the scope and costs of their audit activity, and assess their performance;

(c) formally consider the continuation of or a change in the external auditors and review all issues related to a change of external auditor, including any differences between the Company and the auditor that relate to the auditor's opinion or a qualification thereof or an auditor comment;

(d) recommend to the Board of Directors a firm of external auditors for approval by the shareholders of the Company; review and approve the terms of their engagement; review and approve the fee, scope and timing of the audit, and be apprised of and approve in advance any audit-related services and any non-audit services (which are not prohibited non-audit services) to be provided by the external auditors and the costs thereof, and consider any impact of the provision of such services on the maintenance of their independence, and review the Company's hiring policies regarding employees and former employees of the present and former external auditors;

(e) review all issues related to any proposed change in, or renewal of, the contract with the contract auditor;

(f) review and recommend approval by the Board of Directors of the Company's audited annual financial statements and Management's Discussion and Analysis;

(g) review before publication the Company's unaudited quarterly financial statements, reports of quarterly earnings, and Management's Discussion and Analysis, with particular attention to the presentation of unusual or sensitive matters, such as disclosure of related-party transactions, significant non-recurring events, significant risks, changes in accounting principles, and estimates or reserves, and all significant variances between comparative reporting periods, and approve the publication of the Company's unaudited quarterly financial statements and reports of quarterly earnings;

(h) review all financial information included in Annual Information Forms, prospectuses, other offering memoranda or other documents requiring approval by the Board of Directors;

(i) review the Statement of Management's Responsibility for the Consolidated Financial Statements as signed by senior management and included in any published document and review and approve the statement regarding the role of the Committee as signed by the chairman of the Committee and included in any published documents;

(j) review any litigation, claim or other contingency, including tax assessments, that could have a material effect upon the financial position or operating results of the Company, and ensure appropriate disclosure thereof in documents reviewed by the Committee;

(k) review and ensure the appropriateness and quality of the accounting policies used in the preparation of the Company's financial statements, and consider any proposed changes to such policies;

(l) review with the external auditor the contents of the annual audit report and review any significant recommendations from the external auditor to strengthen the internal controls of the Company;

(m) review the results of the external audit, any significant problems encountered in performing the audit, and the contents of any management letter issued by the external auditor to the Company, and management's response thereto;

(n) annually review a report on the contract audit function with respect to the terms of reference, organization, staffing, independence, performance and effectiveness of the contract audit services, receive and approve the annual contract audit plan, and obtain assurances in respect of conformity with Canadian Institute of Chartered Accountants (CICA) and American Institute of Certified Public Accountants (AICPA) professional standards, and other regulatory bodies' requirements, the out-sourcing contract and recommendations of management and the contract auditor;

(o) review significant contract audit findings and recommendations, and management's response thereto;

(p) receive a report on the Company's internal control policies and procedures with particular emphasis on accounting and financial controls, and recommend changes where appropriate;

(q) review any unresolved significant issues between management and the external auditor that could affect the financial reporting or internal controls of the Company;

(r) receive reports on and review any other items deriving from the foregoing, either in respect of the Company, or a subsidiary or any other entity or relationship in which the Company has a significant interest, as requested by the Board of Directors;

(s) review and make recommendations to the Board of Directors concerning the following:

  (i) the Company's policies regarding hedging, investments, credit and risk management; and

  (ii) the Company's risk identification, analysis and management procedures;

(t) review, prior to each Annual Meeting of shareholders', the policies and practices concerning the regular examination of officers' expenses and perquisites, including the use of Company assets; and

(u) report annually to the full Board of Directors, on the state of completion of the Audit, Finance and Risk Committee annual agenda items, with appropriate recommendations.

2. ORGANIZATION AND PROCEDURES

(a) The Committee shall meet regularly, not less than four times per year, and at such other times as may be requested by the chair of the Committee. The chief executive officer, the chief financial officer, the controller, the contract auditor, the external auditor or any member of the Committee may also request a meeting of the Committee.

(b) The chair of the Committee, in consultation with the chief financial officer, shall set the agenda for each meeting which shall then be circulated among the Committee members.

(c) The chief executive officer, the chief financial officer and the controller shall have direct access to the Committee and shall receive notice of and attend all meetings of the Committee, except private sessions.

(d) The external auditor and the contract auditor shall ultimately report to the Board of Directors and the Committee and shall at any time, have direct access to the Committee and shall receive notice of and be invited to attend all meetings of the Committee, except private sessions.

(e) The contract auditor, the external auditor, and one or more representatives of senior management, shall each meet separately with the Committee, in private sessions, at least once annually.

(f) The Committee may contact directly any employee in the Company and the contract auditor, as it deems necessary.

(g) The Committee will establish procedures for:

  (i) receipt, retention and treatment of complaints regarding accounting controls or auditing matters; and

  (ii) confidential anonymous submission by employees of concerns regarding questionable accounting or auditing matters; and annual review of compliance under the Company's Code of Ethics for senior financial officers.

(h) The Committee will periodically review its own Terms of Reference to ensure they continue to be appropriate, and make recommendations to the Board of Directors, as required.