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

FORM 40 - F

(Check One)

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

or

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

For fiscal year ended: December 31, 2006

Commission File No.: 1-13922

PETRO-CANADA

(Exact name of registrant as specified in its charter)

Canada	**1311, 1321, 1382, 5541**	**Not Applicable**
(Province or other jurisdiction of incorporation or organization)	(Primary standard industrial classification code number, if applicable)	(I.R.S. employer identification number, if applicable)

150 - 6th Avenue S.W.
Calgary, Alberta
Canada T2P 3E3
(403) 296-8000
(Address and telephone number of registrant's principal executive office)

CT Corporation System
111 Eight Avenue - CT
New York, New York 10011
(212) 894-8940
(Name, address and telephone number of agent for service in the United States)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class:	Name of each exchange on which registered:
Common Shares	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act:

None

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act:

5% Senior Notes due 2014
9 ¼% Debentures Due 2021
7 7/8% Debentures Due 2026
7% Debentures Due 2028
4% Senior Notes Due 2013
5.35% Senior Notes Due 2033
5.95% Senior Notes Due 2035

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

__x___ Annual Information Form __x___ Audited Financial Statements

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the periods covered by the annual report:

Common Shares: 497,538,385

Indicate by check mark whether the registrant by filing the information contained in this form is also thereby furnishing the information to the Commission pursuant to Rule 12g 3-2(b) under the Securities Exchange Act of 1934 (the "Exchange Act"). If "Yes" is marked, indicate the file number assigned to the registrant in connection with such rule.

Yes ______ No __x___

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

Yes __x___ No ______

CAUTIONARY NOTICE REGARDING FORWARD LOOKING INFORMATION

This Form 40-F contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities and Exchange Act of 1934. 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 business strategy and goals; references to future capital and other expenditures; drilling plans; construction activities; refinery turnarounds; the submission of development plans; seismic activity; refining margins; oil and 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 and resources estimates; reserves life-of-field estimates; natural gas export capacity; and environmental matters. By their very nature, these forward-looking statements require Petro-Canada to make assumptions, that may not materialize or that may not be accurate, 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: imprecision of reserves estimates of recoverable quantities of oil, natural gas and liquids from resource plays and other sources not currently classified as reserves; general economic, market and business conditions; industry capacity; competitive action by other companies; fluctuations in oil and gas prices; refining and marketing margins; the ability to produce and transport crude oil and natural gas to markets; the effects of weather and climate conditions; the results of exploration and development drilling and related activities; fluctuation 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; both domestic and international; international political events; expected rates of return; and other factors, many of which are beyond the control of Petro-Canada. These factors are discussed in greater detail elsewhere in this Form 40-F.

Readers are cautioned that the foregoing list of important factors affecting forward-looking statements is not exhaustive. Furthermore, the forward-looking statements contained herein are made as of the date of this Form 40-F, 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 Form 40-F are expressly qualified by this cautionary statement.

Clear. Capable. Committed.

PETRO-CANADA

ANNUAL INFORMATION FORM 2006

March 22, 2007

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Presentation of Information

The information contained in this Annual Information Form (AIF) is dated as at December 31, 2006, unless otherwise indicated. 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 (e.g. North American Natural Gas, East Coast Oil, Oil Sands, International and Downstream). Dollars are Canadian, unless otherwise stated. All oil and natural gas production and reserves volumes are stated before deduction of royalties, unless otherwise indicated.

Conversion Factors

To conform with common usage, imperial units of measurement are used in this AIF to describe exploration and production, while metric units are used for refining and marketing.

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 Measures

Cash flow, which is expressed as cash flow from operating activities before changes in non-cash working capital, is used by the Company to analyse operating performance, leverage and liquidity. Operating earnings represent net earnings, excluding gains or losses on foreign currency translation, disposal of assets and unrealized gains or losses on the mark-to-market valuation of the derivative contracts associated with the Buzzard acquisition. Operating earnings are used by the Company to evaluate operating performance. Cash flow and operating earnings do not have a standardized meaning prescribed by Canadian generally accepted accounting principles (GAAP) and, therefore, may not be comparable with the calculation of similar measures for other companies. For reconciliation of the operating earnings and cash flow amounts to the associated GAAP measures, refer to the tables on pages 12 and 14, respectively, of Petro-Canada's Management's Discussion and Analysis (MD&A) dated February 12, 2007, as contained in the 2006 Annual Report.

Legal Notice - Forward-Looking Information

This AIF contains forward-looking information. You can usually identify this information by such words as *"plan," "anticipate," "forecast," "believe," "target," "intend," "expect," "estimate," "budget"* or other similar wording suggesting future outcomes or statements about an outlook. We list below examples of references to forward-looking information:

- business strategies and goals
- outlook (including operational updates and strategic milestones)
- future capital, exploration and other expenditures
- future resource purchases and sales
- construction and repair activities
- refinery turnarounds
- anticipated refining margins
- future oil and gas production levels and the sources of their growth
- project development and expansion schedules and results
- future 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 and resources estimates
- royalties and taxes payable
- production life-of-field estimates
- natural gas export capacity
- future financing and capital activities (including purchases of Petro-Canada common shares under the Company's normal course issuer bid (NCIB) program)
- contingent liabilities (including potential exposure to losses related to retail licensee agreements)
- environmental matters
- future regulatory approvals

Such forward-looking information is subject to known and unknown risks and uncertainties. Other factors may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such information. Such factors include, but are not limited to:

- industry capacity
- imprecise reserves estimates of recoverable quantities of oil, natural gas and liquids from resource plays and other sources not currently classified as reserves
- the effects of weather and climate conditions
- the results of exploration and development drilling and related activities
- the ability of suppliers to meet commitments
- decisions or approvals from administrative tribunals
- risks attendant with domestic and international oil and gas operations
- expected rates of return
- general economic, market and business conditions
- competitive action by other companies
- fluctuations in oil and gas prices
- refining and marketing margins
- the ability to produce and transport crude oil and natural gas to markets
- fluctuations in interest rates and foreign currency exchange rates
- actions by governmental authorities, including changes in taxes, royalty rates and resource-use strategies
- changes in environmental and other regulations
- international political events

Many of these and other similar factors are beyond the control of Petro-Canada. Petro-Canada discusses these factors in greater detail in filings with the Canadian provincial securities commissions and the United States (U.S.) Securities and Exchange Commission (SEC).

We caution readers that this list of important factors affecting forward-looking information is not exhaustive. Furthermore, the forward-looking information in this AIF is made as of March 22, 2007 and, except as required by applicable law, Petro-Canada does not update it publicly or revise it. This cautionary statement expressly qualifies the forward-looking information in this AIF.

Petro-Canada disclosure of reserves

Petro-Canada's qualified reserves evaluators prepare the reserves estimates the Company uses. The Canadian provincial securities commissions do not consider our reserves staff and management as independent of the Company. Petro-Canada has obtained an exemption from certain Canadian reserves disclosure requirements that allows us to make disclosure in accordance with SEC standards. This exemption allows comparisons with U.S. and other international issuers.

As a result, Petro-Canada formally discloses its reserves data and other oil and gas data using U.S. requirements and practices, and these may differ from Canadian domestic standards and practices. Note that when we use the term barrel of oil equivalent (boe) in this AIF, it may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet (Mcf) to one barrel (bbl) is based on an energy equivalency conversion method. This method primarily applies at the burner tip and does not represent a value equivalency at the wellhead.

To disclose reserves in SEC filings, oil and gas companies must prove they are economically and legally producible under existing economic and operating conditions. Proof comes from actual production or conclusive formation tests. The use of terms such as *"probable," "possible," "recoverable,"* or *"potential reserves and resources"* in this AIF does not meet the SEC guidelines for SEC filings.

The table below describes the industry definitions that we currently use:

Definitions Petro-Canada uses	**Reference**
Proved oil and gas reserves (includes both proved developed and proved undeveloped)	U.S. SEC reserves definition (Accounting Rules Regulation S-X 210.4-10, FASB-69)
Unproved reserves, probable and possible reserves	CIM (Petroleum Society) definitions (Canadian Oil and Gas Evaluation Handbook, Vol. 1 Section 5)
Contingent and prospective resources	Society of Petroleum Engineers, World Petroleum Congress and American Association of Petroleum Geologist definitions (approved February 2000)

There is no certainty that it will be economically viable or technically feasible to produce any portion of the resources. For use in this AIF, *"total resources"* means reserves plus resources.

SEC regulations do not define proved reserves from our oil sands mining operations as an oil and gas activity. These reserves are classified as a mining activity and are estimated in accordance with SEC Industry Guide 7. For internal management purposes, we view these reserves and their development as part of our total exploration and production operations.

Throughout this AIF, total Company reserves, total Company production, total Company reserves replacement and total Company reserves life index (RLI) are calculated using the sum of oil and gas activities, and oil sands mining activities. Before royalties, oil sands mining 2006 year-end proved reserves were 345 million barrels (MMbbls) and oil sands mining annual 2006 production was 11 MMbbls.

CORPORATE STRUCTURE

Incorporation of Petro-Canada

Petro-Canada is a corporation incorporated under the *Canada Business Corporations Act*. 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.

Intercorporate Relationships

Material operating subsidiaries owned 100%, directly or indirectly, by the Company as at December 31, 2006 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.

Individually, the Company's remaining subsidiaries accounted for (i) less than 10% of the Company's consolidated revenues and consolidated assets as at December 31, 2006, and (ii) less than 10% of the Company's consolidated sales and operating revenues as at December 31, 2006. In the aggregate, the remaining subsidiaries accounted for less than 20% of each of (i) and (ii) described above.

Business of Petro-Canada

The following business description should be read in conjunction with Petro-Canada's MD&A, as contained in the 2006 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 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 feedstock, and markets and distributes petroleum products and related goods and services, primarily in Canada.

The table below outlines the various businesses of Petro-Canada as at December 31, 2006.

Upstream

North American Natural Gas
- Western Canada
  - *Alberta Foothills*
  - *Southeast Alberta/ Southwest Saskatchewan*
  - *West Central Alberta*
  - *Northeast British Columbia*
- U.S. Rockies
- Mackenzie Delta/Corridor
- Alaska

East Coast Oil[1]
- Hibernia (20% Interest)
- Terra Nova (34% Interest)
- White Rose (27.5% Interest)
- Other Significant Discoveries and Exploration Acreage

Oil Sands
- Syncrude (12% Interest)
- MacKay River (100% Interest)
- Fort Hills (55% Interest)
- Other *In Situ* Oil Sands Leases

International[1]
- Northwest Europe
  - *Buzzard (29.9% Interest)*
- North Africa/Near East
- Northern Latin America

Downstream

Refining and Supply
- Montreal Refinery
- Edmonton Refinery
- ParaChem Chemical Plant (51% Interest)

Sales and Marketing
- Retail Operations
- Wholesale Operations

Lubricants
- Mississauga Lubricants Centre

1 In 2007, Petro-Canada is consolidating its East Coast Oil and International businesses. The purpose of the consolidation is to leverage and grow the capabilities of similar operations.

GENERAL DEVELOPMENT OF THE BUSINESS

Three-Year History

The following narrative is a three-year history of notable Company events:

2006

Petro-Canada finished 2006 with solid operating earnings and cash flow. The Company achieved first production from upstream growth initiatives, record financial results in the Downstream, East Coast Oil and in Oil Sands due to a strong business environment, and advanced long-term projects to deliver the next wave of earnings and cash flow growth. Specifically, the Company:

- delivered operating earnings adjusted for unusual items of approximately $2 billion and cash flow of about $3.7 billion
- finished 2006 with a proved plus probable reserves replacement ratio of 175% over five years[1]
- achieved first production from the North Sea platforms of De Ruyter and L5b-C, as well as from the Syncrude Stage III expansion
- completed lubricants plant expansion, and Downstream ultra-low sulphur diesel refinery projects to produce cleaner burning fuels
- secured drilling rigs for the 2007 and 2008 International exploration program

The Oil Sands business delivered record operating earnings of $245 million for the year, reflecting additional production from the ramp up of the Syncrude Stage III expansion and favourable bitumen pricing. At the same time, the Company added *in situ* oil sands resources with the purchase of additional leases adjacent to MacKay River. As part of the Fort Hills project, in December 2006, the partners filed a regulatory application to construct and operate an upgrader in Sturgeon County, about 40 kilometres northeast of Edmonton.

In 2006, East Coast Oil also delivered record operating earnings of $934 million, reflecting higher realized prices. Petro-Canada completed the extended turnaround of the Terra Nova Floating Production Storage and Offloading (FPSO) vessel, which involved regulatory inspections and reliability improvements. Development drilling in the White Rose field showed promise in 2006, with discoveries made in the west and southwest sections of the field. Additional information is being gathered and evaluated to determine the size of any additional reserves these formations may hold. The partner-operated Hibernia platform continued to have solid operations; however, regulatory decisions on the Southern Extension, originally expected in 2006, were deferred to 2007. In April 2006, Petro-Canada and its partners in the Hebron development suspended negotiations with the Government of Newfoundland and Labrador and demobilized the Hebron project team after failing to reach a development agreement. Petro-Canada continues to consider Hebron a high quality asset.

In the International business unit in early 2006, Petro-Canada completed the sale of the Company's producing assets in Syria for net proceeds of $640 million. The sale resulted in a gain on disposal of $134 million. Later in the year, the Company completed an agreement to purchase a 90% interest in the Ash Shaer and Cherrife natural gas fields in central Syria for $54 million. Under this agreement, Petro-Canada will act as operator and will have the option to purchase the remaining 10% interest within five years, subject only to approval by the Syrian government. The changes made in Syria in 2006 align with Petro-Canada's strategy to increase the proportion of long-life and operated assets within its portfolio.

In North American Natural Gas, Western Canada production continued to decline in 2006 as expected. Lower earnings in 2006 reflected lower realized prices combined with decreased Western Canada volumes and higher operating costs. These factors were partially offset by additional U.S. Rockies production. Increased operating costs in 2006 were primarily due to rising industry-wide cost pressures. In the U.S. Rockies, water treatment permits required for wells planned in 2005 and 2006 were approved, resulting in a ramp up of coal de-watering. The Company continues to drill in the Denver-Julesburg Basin for natural gas from tight sands. A public hearing on the proposed liquefied natural gas (LNG) import and re-gasification terminal at Gros-Cacouna, Quebec was held and the Company expects to receive a regulatory decision in 2007. The Company also continued to position itself for long-term North American supply by assessing its exploration prospects in Alaska and Mackenzie Delta/Corridor. Petro-Canada is developing a resource position in the North in advance of proposed pipelines.

In 2006, the Downstream delivered record operating earnings of $463 million, due to the strong business environment combined with solid operations. Early in 2006, a fire occurred at the Mississauga lubricants plant, which reduced output to 50% of plant capacity for approximately two months. The lubricants plant repairs were completed in March and, in June, the facility began ramping up its 25% expansion project. In the second quarter of 2006, Petro-Canada completed its ultra-low sulphur diesel projects at its Edmonton and Montreal refineries, thereby providing cleaner burning fuels to consumers. The two refineries operated at a combined reliability index of 95 in 2006. During the year, construction was started to convert the Edmonton refinery to process 100% bitumen-based feedstock and work progressed to evaluate the feasibility of adding a coker to the Montreal refinery.

The Company also returned funds to shareholders during the year. On December 14, 2006, the Company declared a 30% increase in its quarterly dividend to $0.13/share commencing with the dividend payable April 1, 2007. Total cash dividends paid in 2006 were $201 million, compared with $181 million in 2005 and $159 million in 2004. In addition, Petro-Canada renewed its NCIB program. The current program, which extends to June 21, 2007, entitles the Company to purchase up to 5% of its outstanding common shares, subject to certain conditions. During 2006, the Company repurchased and cancelled 19,778,400 shares at an average price of $51.10 per share for a total cost of just over $1 billion.

2005

In 2005, Petro-Canada had record operating earnings adjusted for unusual items of approximately $2.4 billion and cash flow of about $4 billion. The Oil Sands business strengthened its position in mining bitumen by securing a majority interest and operatorship of the Fort Hills project from UTS Energy Corporation (UTS). Petro-Canada is project operator with a 55% interest, UTS has a 30% interest and Teck Cominco holds a 15% interest. The Company also strengthened its East Coast Oil position in 2005 with first oil at White Rose on budget and ahead of schedule. In late 2005, Petro-Canada reached an agreement to sell the Company's producing assets in Syria for EUR 484 million (Canadian equivalent of $676 million as at December 20, 2005), before adjustments. The sale closed on January 31, 2006. Other achievements during 2005 include the advancement of the proposed LNG import and re-gasification terminal at Gros-Cacouna, Quebec, by filing an Environmental Impact Statement. Also, the Company continued to position itself for long-term North American supply by building its land position in the Mackenzie Delta/Corridor and by acquiring extensive acreage in Alaska in preparation for the proposed pipelines. In the Downstream, the Company completed the Eastern Canada refinery consolidation and acquired a 51% interest in a paraxylene facility adjacent to the Montreal refinery. In addition, Petro-Canada increased sales at convenience stores and in its high margin lubricants. The Company also returned funds to shareholders during the year. In July 2005, the Company declared a two-for-one stock split in the form of a stock dividend. Commencing with the fourth quarter dividend paid on October 1, 2005, the Company increased the quarterly dividend 33% to $0.20/share on a pre-stock dividend basis ($0.10/share on a post-stock dividend basis). In addition, Petro-Canada renewed the NCIB program, which was extended to June 21, 2006, entitling the Company to purchase up to 5% of its outstanding common shares, subject to certain conditions. During 2005, the Company repurchased and cancelled 8,333,400 shares (on a post-stock dividend basis) at an average price of $41.54 per share for a total cost of approximately $346 million. During the second quarter of 2005, Petro-Canada completed a $600 million US offering of 5.95% 30-year senior notes. Net proceeds were used to repay existing short-term borrowing, with the balance used for working capital purposes.

1 See Legal Notice on page 1, regarding oil and gas and oil sands mining activities.

2004

In 2004, the Company achieved then record operating earnings adjusted for unusual items of about $1.9 billion and record cash flow of approximately $3.6 billion. During 2004, North American Natural Gas acquired an interest in the U.S. Rockies with the purchase of Prima Energy Corporation for $644 million. 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. 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. Petro-Canada continued to focus on the global LNG business and signed a Memorandum of Understanding (MOU) with TransCanada PipeLines Limited (TransCanada PipeLines) to develop and share (50/50) ownership of an 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. In the Downstream, the Company successfully advanced 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. The Company also returned funds to shareholders during the year by increasing its quarterly dividend to $0.15/share and commencing an NCIB to repurchase a portion of its outstanding common shares. In the fourth quarter of 2004, the Company issued $400 million US of 10-year senior notes. The net proceeds were used to repay the U.S. Rockies acquisition credit facility. 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/share, resulting in total gross proceeds to the government of approximately $3.2 billion.

DESCRIPTION OF THE BUSINESS

Business Environment

The major economic factors influencing Petro-Canada's upstream financial performance include crude oil and natural gas prices, and foreign exchange, particularly the Canadian dollar/U.S. dollar rates. Crude oil and natural gas prices are affected by a number of factors, including supply and demand balance, weather and political events. Factors influencing Downstream financial performance include the level and volatility of crude oil prices, industry refining margins, movements in crude oil price differentials, demand for refined petroleum products and the degree of market competition.

Business Environment in 2006

The year 2006 was characterized by volatile crude oil and natural gas prices. The price of North Sea Brent (Dated Brent) moved between highs in excess of $77 US/bbl, to lows of almost $55 US/bbl. Similarly, benchmark North American natural gas prices at the Henry Hub fluctuated between highs in excess of $10 US/million British thermal units (MMBtu) to lows close to $4 US/MMBtu.

On an annual average basis, the price of Dated Brent reached $65.14 US/bbl, its highest annual average value ever and almost 20% higher than the average in 2005. High oil prices in 2006 were driven by continuing demand growth from China and increased geopolitical tensions globally. Relative to last year, international light/heavy crude (Dated Brent/Mexican Maya) price differentials stabilized in 2006 around the $14 US/bbl level, while Canadian light/heavy crude (Edmonton Light/Western Canada Select) spreads narrowed noticeably.

The continuing appreciation of the Canadian dollar during 2006 reduced the positive impact of higher international prices on Canadian crude prices. The Canadian dollar averaged 88 cents US in 2006, compared with 83 cents US in 2005.

North American natural gas prices suffered a setback during 2006. Record high levels of gas in storage and lower weather-related demand led to significantly lower prices, compared with 2005. Henry Hub prices averaged $7.26 US/MMbtu in 2006, 15% lower than in 2005. Natural gas prices in 2005 reflected the severe impact of hurricanes on U.S. Gulf of Mexico production. In 2006, the Canadian natural gas price at the AECO-C hub fell in line with U.S. prices and averaged almost 18% below its 2005 level.

In the downstream sector, it is estimated that, in 2006, refined petroleum product sales in Canada declined by 1% on top of the 1% reduction in 2005. In spite of lower overall industry product sales and relatively unchanged international light/heavy crude price spreads, overall refining margins increased in 2006, compared with 2005. The impact of the introduction of ultra-low sulphur diesel in the U.S. and Canada effective June 2006 was to maintain heating crack spreads at strong levels. The phasing out of Methyl Tertiary Butyl Ether (MTBE) from gasoline in the U.S. and a heavy refinery turnaround season helped to improve gasoline margins relative to 2005.

Competitive Conditions

It is becoming increasingly challenging for the energy sector to find new sources of oil and gas. Petro-Canada is well positioned to compete successfully for new opportunities that could complement existing upstream resources and increase production of oil and gas. The Company has an estimated 15.9 billion boe of total resources from which to develop new production. Approximately two-thirds of total resources are located in Alberta's oil sands. As well, with different upstream businesses operating in Canada and internationally, the Company has the flexibility to pursue a wide range of opportunities. While the Company has wide operational scope, it remains a mid-sized global company as measured by production levels. This means Petro-Canada has the operational capability and balance sheet strength to invest in large projects, but smaller acquisitions can also impact the Company's production levels and financial returns.

Petro-Canada is well positioned to compete in the petroleum product refining and marketing business in Canada. The Company accounts for 13% of the total refining capacity in Canada and has a 16% share of the petroleum products market in Canada. Its 1,312 retail service station network has the highest gasoline sales per site in Canada among the national integrated oil companies. It also has Canada's largest commercial road transport network, with 219 locations, as well as a robust bulk fuel sales channel.

The Company believes that its strong financial position, combined with a track record of executing large capital projects and depth of management experience will enable it to continue to compete successfully in the current business environment.

Risk Management

PETRO-CANADA'S RISK PROFILE

Petro-Canada's results are impacted by risk and management's strategy for handling risks. Petro-Canada characterizes and manages risks in four broad categories: business risks, market risks, operational risks and foreign risks. Within these categories, risks are listed in alphabetical order below. 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.[1] The following describes Petro-Canada's approach to managing major risks.

BUSINESS RISKS

Counterparties

Petro-Canada is exposed to credit risk due to the uncertainty of business partners' or counterparties' ability to fulfil their obligations. The Company has 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.

Environmental Regulations

Petro-Canada has always been subject to the impact of changing environmental regulations on its operations; however, the risk is considered to be increasing as related laws and regulations become more stringent in Canada and in other countries where Petro-Canada operates. Petro-Canada invests capital to satisfy new product specifications and/or address environmental issues. In 2007, the Company anticipates that it will invest $100 million of its capital expenditure program toward regulatory compliance. As well, the Company conducts Life-Cycle Value Assessments (LCVA), a system to integrate and balance environmental, social and economic decisions for major projects. This process encourages the exploration of alternatives when considering the life-cycle of an asset or product from construction through to abandonment. The LCVA is a useful technique, but it cannot predict changes in environmental regulations. As a result, changes in environmental regulations may impact Petro-Canada's business results.

The Kyoto Protocol, effective in Canada since 2005, requires signatory nations to reduce their emissions of carbon dioxide and other greenhouse gases. The details of implementation of the Protocol in Canada have not been finalized. Depending on the specifics of the regulations, Petro-Canada may be required to reduce emissions of greenhouse gases from operations, to purchase emission-trading credits or pay for other types of offsets. The impact on Petro-Canada could result in substantially higher capital expenditures and/or 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 industry-wide margins for refined products. Through industry organizations, Petro-Canada works with a number of regulatory groups and government associations to find an approach that will minimize the negative financial impact of the greenhouse gas emission regulations on the Company, while still reducing emissions. The level of influence these efforts have on the Government of Canada's implementation plan may be quite limited.

1 Further detail regarding the Audit, Finance and Risk Committee can be found on page 80 of the AIF and a copy of its Charter is attached as Schedule C.

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 the contracting of exploration and production interests, impose specific drilling obligations, and expropriate or cancel contract rights. Governments may also regulate prices of commodities or refined products, or intervene indirectly on prices through taxes, royalties and exploration rights.

Petro-Canada tries to mitigate the potentially disruptive impact of government regulations by selecting operating environments with stable governments and by maintaining respectful relationships with governments and regulators. Contact with regulators and governments usually occurs through the Company's management and/or regulatory affairs and government relations personnel. 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 where it operates. By virtue of Petro-Canada's integrated portfolio of businesses, the Company 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 that may have a material adverse effect on the Company.

Licence to Operate

Petro-Canada's oil and gas production and refining operations impact communities and surrounding environments. Those impacted can become concerned over the use of scarce resources, such as land and water, the perceived or real threat to human health, the potential impact on biodiversity, and/or possible societal changes to surrounding communities. Petro-Canada must secure and maintain formal regulatory approvals and licences to conduct its operations. In addition, broader societal acceptance of the Company’s activities is necessary for resource development. An inability for Petro-Canada to secure local community support, necessary regulatory approvals and licences, and broader societal acceptance can result in projects being delayed or stopped, increasing project costs and damage to the Company's reputation. Lack of local community and stakeholder support can also lead to pressure to limit or shut down operations.

Petro-Canada manages this risk by applying a set of Principles for Responsible Investment and Operations to its businesses. These Principles provide a framework whereby Petro-Canada's operations around the world are conducted in a manner that is economically rewarding to all parties and recognized as being ethically, environmentally and socially responsible. These Principles and the Company's activities in support of them can be found on Petro-Canada's website at www.petro-canada.ca. Even though Petro-Canada is committed to following its Principles and respecting two-way dialogue with applicable stakeholders, there is no guarantee the Company will be granted the licences needed to operate projects within expected timelines or that its reputation with affected stakeholders will not be damaged.

Non-Operated Interests

Petro-Canada has a significant interest in assets where the management of construction or operation is done by other companies. 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% interest) and Buzzard (29.9% interest). Joint venture executive committees manage major projects, so Petro-Canada does have some ability to influence these projects. As well, Petro-Canada has joint venture or other operating agreements, which specify the Company's expectations from third-party operators. Nevertheless, third-party operation and management of the Company's assets could adversely affect Petro-Canada's financial performance.

Project Execution

Petro-Canada manages a variety of projects to support continuing operations and future growth. Petro-Canada's goal is to consistently deliver projects in alignment with expectations. Project execution risks include, but are not limited to, changes in project scope, labour availability and productivity, material and services availability and costs, design and construction errors, regulatory approvals, and project management and operational capability. To mitigate these risks, Petro-Canada applies a project delivery management system, establishes strong project management teams, breaks large projects down into manageable components, builds on experience and existing technologies, works with all stakeholders on safety and environmental expectations, and conducts post-project reviews to improve project management and operational capabilities. Petro-Canada primarily delivers projects through engineering, procurement and construction (EPC) companies. Through the establishment of strong internal project management teams, the Company establishes effective working relationships with EPC companies.

In 2006, Petro-Canada completed a number of projects, including converting refineries to produce cleaner burning fuels, expansion of the lubricants plant and bringing the Company-operated De Ruyter project in the North Sea on-stream. These projects represented $1.7 billion of investment, which was completed on time and on budget. Nevertheless, the inability of Petro-Canada to execute projects as expected is a risk to the Company. Globally, there is a focus on execution and projects are tending to be larger and more complex at the same time as the pool of experienced personnel is declining. The Company has recognized the need to provide the organizational capability to successfully execute these projects and, as such, has been building its capabilities through recruiting and internal training; however, the inability to adequately source the staffing requirements could jeopardize successful project execution.

Reserves Estimates

Estimates of economically recoverable oil and gas reserves are based upon a number of variables and assumptions. These 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 auditor, has tested aspects of the non-engineering control processes Petro-Canada used in establishing reserves. As well, independent engineering firms assess a significant portion of 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 reserves booking practices can be found in the Reserves section of this AIF.

Reserves Replacement[1,2]

Petro-Canada's future cash flows from continuing operations are highly dependent on its ability to offset natural declines as reserves are produced. As basins mature, replacement of reserves becomes more challenging and expensive. In some geographic areas, the Company may choose to allow its reserves to decline if replacement is uneconomical, pursuing other reserves additions instead from successful exploration or acquisitions.

Petro-Canada's reserves objective is to fully replace proved reserves over a five-year period. In 2006, the Company replaced 134% of its production on a proved reserves basis, compared with 111% in 2005. The Company's five-year proved replacement ratio was 160% at year-end 2006. There is no assurance Petro-Canada will successfully replace reserves that are produced in any given year.

MARKET RISKS

More detailed quantification of the impact of some of the following risks can be found in the earnings sensitivities table on page 5 of the Business Environment section in the MD&A dated February 12, 2007.

Commodity Prices

The prices of crude oil and natural gas fluctuate in response to market factors that are external to Petro-Canada. Commodity prices are volatile and influenced by factors such as supply and demand fundamentals, geopolitical events, Organization of the Petroleum Exporting Countries (OPEC) decisions and weather. For historical commodity prices, please refer to page 4 of the Business Environment section in the MD&A dated February 12, 2007. Changes in crude oil and natural gas prices affect the price that Petro-Canada receives for its upstream production. Commodity prices also impact the refined product margins realized in the Downstream business. Petro-Canada's ability to maintain product margins in an environment of higher feedstock costs is contingent upon the Company's ability to pass on higher costs to customers.

1 See Legal Notice on page 1, regarding oil and gas and oil sands mining activities.
2 Proved reserves replacement ratio is calculated by dividing the year-over-year net change in proved reserves, before deducting production, by the annual production over the same period. The reserves replacement ratio is a general indicator of the Company’s reserves growth. It is only one of a number of metrics that can be used to analyse a company’s upstream business.

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/or to reduce commodity price risk on specific exposures. Certain Downstream physical transactions are routinely hedged for operational needs and to facilitate sales to customers.

Foreign Exchange

Because energy commodity prices are primarily in U.S. dollars, 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 strategy lets the Company take advantage of lower interest rates on floating debt, while matching overall debt maturities with the life of cash-generating assets. While 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. Periodically, the Company reviews the proportion of fixed to floating rate debt issued.

Derivative Instruments

Petro-Canada has a formal policy that prohibits the use of derivative instruments for speculative purposes. All derivative instruments entered into are for the purpose of mitigating identified price risks.

Petro-Canada continually monitors outstanding derivative instruments. This includes an assessment of fair values of all derivative instruments using independent third-party quotes to determine the value of each derivative instrument. The objectives of all price risk mitigation transactions are documented, and the effectiveness of each derivative instrument in offsetting the identified price risk is periodically assessed. Petro-Canada also limits the transaction term of its derivative instruments.

The Company applied mark-to-market accounting treatment to all derivative transactions that it entered into in 2006. Realized and unrealized gains and losses resulting from changes in the fair value of derivative instruments that do not qualify for hedge accounting are recognized in "Investment and Other Income." For derivative instruments that qualify for hedge accounting, Petro-Canada may elect to apply hedge accounting treatment.

During 2004, 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 Dated Brent crude oil. The purpose of these transactions was to ensure value-added 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 bbls. This volume represents approximately 50% of the Company's share of estimated plateau production from July 1, 2007 to December 31, 2010. As at December 31, 2006, the Buzzard derivative instruments had a recognized mark-to-market unrealized loss of $1,007 million after-tax, of which $240 million was recognized in the income statement in 2006.

In 2006, other derivative instruments in place for refining supply and product purchases resulted in an increase in net earnings from continuing operations of about $1 million after-tax, compared with an increase of about $4 million in 2005.

OPERATIONAL RISKS

Exploring for, developing, producing, refining, transporting and marketing oil, natural gas and refined products involve significant operational risks. These risks include situations such as well blowouts, fires, explosions, gaseous leaks, equipment failures, migration of harmful substances and oil spills. Any of these operational incidents, including events beyond the Company's control, could cause personal injury, environmental contamination, interruption of production, and/or damage and destruction of the Company's assets.

Petro-Canada manages operational risks primarily through a Total Loss Management (TLM) system that has standards to prevent losses. Regular TLM audits test compliance with these standards. The Company also has a Zero-Harm philosophy, a belief that injuries and illnesses, on and off the job, are foreseeable and preventable.

The Company also purchases insurance to transfer the financial impact of some operational risks to third-party insurers. On an annual basis, Petro-Canada management evaluates its operational risk exposures and adjusts its insurance coverage, including deductibles and limits. While Petro-Canada maintains insurance consistent with industry practices, the Company cannot and does not fully insure against all risks. Losses resulting from operational incidents could have an adverse impact on the Company.

Interruption to production at any one of Petro-Canada's facilities could result in an adverse financial impact; however, the risk of multiple facilities experiencing production interruptions at the same time is mitigated by having multiple large producing and upgrading assets in various geographic locations throughout the world.

FOREIGN RISKS

Petro-Canada has significant operations 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 of actions by governmental authorities, internal unrest, war, political disruption, economic and legal sanctions (such as restrictions against countries that the U.S. government may deem to sponsor terrorism), and changes in global trade policies. The Company's operations may be restricted, disrupted or prohibited in any country in which these risks occur. Petro-Canada also has production in countries that are members of OPEC, which has resulted in, and may result in, the future for production volumes to be constrained by 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 purchases political risk insurance to partially mitigate certain political risks.

Upstream

Petro-Canada's upstream operations consisted of four business segments in 2006: 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 Northeast Alberta; and International, where the Company is active in three core areas: Northwest Europe, North Africa/Near East and Northern Latin America. The diverse asset base provides a balanced portfolio and a platform for long-term growth. In 2007, Petro-Canada is consolidating its East Coast Oil and International businesses. The purpose of the consolidation is to leverage and grow the capabilities of similar operations.

North American Natural Gas

Business Summary and Strategy

North American Natural Gas explores for and produces natural gas, and crude oil and NGL in Western Canada and the U.S. Rockies. This business also markets natural gas in North America and has established resources in the Mackenzie Delta/Corridor and Alaska.

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

- targeting 75% to 80% reserves replacement
- transitioning further into unconventional gas plays
- optimizing core properties in Western Canada and developing coal bed methane (CBM) and tight gas in the U.S. Rockies
- increasing the focus on exploration
- developing LNG import capacity at Gros-Cacouna, Quebec
- building the northern resource base for long-term growth

Western Canada and U.S. Rockies

Annual production before royalties totalled 225 billion cubic feet (Bcf) of natural gas and 5.2 MMbbls of conventional crude oil and NGL in 2006. Exploration and development drilling activity in North American Natural Gas resulted in 676 gross (523 net) wells, including 569 gross (427 net) natural gas wells and 78 gross (71 net) oil wells, for an overall success rate of 96% in 2006.

The North American realized natural gas price averaged $6.85/Mcf in 2006, down 19% from $8.47/Mcf in 2005.

Western Canada natural gas production averaged 646 million cubic feet of equivalent/day (MMcfe/d) in 2006, down 8% from 704 MMcfe/d in 2005. Exploration and development drilling activity in Western Canada resulted in 393 successful wells (gross), for an overall success rate of 93% in 2006. Western Canada operating and overhead costs were $1.31/ thousand cubic feet of equivalent (Mcfe) in 2006, up from $1.10/Mcfe in the previous year. The operating and overhead cost increase in Western Canada reflected general industry-wide cost pressures for materials, fuel and labour, combined with lower production.

During 2004, the North American Natural Gas business grew to include unconventional natural gas operations in the U.S. Rockies. The Company acquired production from CBM in the Powder River Basin and tight gas in the Denver-Julesburg Basin, as well as significant expertise in unconventional production. Petro-Canada is focused on doubling U.S. Rockies production to 100 MMcfe/d by the end of 2007.

U.S. Rockies natural gas production averaged 55 MMcfe/d in 2006, up 6% from 52 MMcfe/d in 2005. The increase reflected natural gas breakthrough at the Wild Turkey CBM field. Exploration and development drilling activity in the U.S. Rockies during 2006 resulted in more than 280 gross wells, down from 300 wells in 2005. In addition, Petro-Canada obtained 396 permits for new CBM wells in 2006, with 363 applications submitted for consideration. Most of the new CBM wells are currently in the de-watering phase. U.S. Rockies operating and overhead costs were $2.29/Mcfe in 2006, compared with $1.84/Mcfe in 2005. This increase reflected costs associated with the increasing number of wells, along with general industry-wide cost pressures.

The Company continued the strategic shift to increased unconventional production by acquiring approximately 50,000 net exploration acres of tight gas prone land for future development, including approximately 36,000 net acres in the Uinta Basin in eastern Utah.

In Western Canada, Petro-Canada operates 10 natural gas field processing plants with total licensed capacity of approximately one billion cubic feet/day (Bcf/d), of which the Company's share is approximately 622 million cubic feet/day (MMcf/d). As part of the Company's ongoing optimization of its portfolio of assets, in early 2007, Petro-Canada completed the sale of its 31% working interest in the Brazeau plant and the majority of its 10% working interest in the West Pembina plant. The following table shows Petro-Canada's working interest ownership and the capacity of operated processing plants.

PETRO-CANADA OWNERSHIP AND CAPACITY[1]

Petro-Canada Operated Plants	Working Interest Ownership *(%)*	Gross Licensed Capacity *(MMcf/d)*	Net Licensed Capacity *(MMcf/d)*
Hanlan Sweet	41	44	18
Hanlan Sour	46	380	175
Total Hanlan		**424**	**193**
Wilson Creek Sweet	52	12	7
Wilson Creek Sour	52	22	11
Total Wilson Creek		**34**	**18**
Boundary Lake Sweet	100	20	20
Boundary Lake Sour	50	66	33
Parkland 1	44	18	8
Parkland 2	35	12	4
Wildcat Hills	66	124	82
Bearberry	100	94	94
Ferrier	99	119	118
Gilby East	100	52	52
Total 2006		**963**	**622**

1 Excludes the Brazeau operated plant sold in January 2007.

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 aggregate share from such interests is 197 MMcf/d of licensed capacity.

In 2006, North American Natural Gas marketed 716 MMcf/d of natural gas, of which 664 MMcf/d were direct sales. Approximately 11% (81 MMcf/d) of total sales were internal to Petro-Canada, at market prices, and were used at refinery and lubricant facilities as fuel and for some plant feedstock, and steam generation at the MacKay River *in situ* operation. 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 673 MMcf/d in 2006, down 13% from 772 MMcf/d in 2005, reflecting lower production and third-party sales. U.S. Rockies sales for 2006 were 43 MMcfe/d, compared with 41 MMcfe/d in 2005. Higher 2006 sales reflect natural gas breakthrough at the Wild Turkey CBM field in the third quarter of 2006. 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 contracts, pipeline commitments and customer relationships.

The following table shows the market distribution of Petro-Canada's North American Natural Gas sales.

NORTH AMERICAN NATURAL GAS SALES BY MARKET

	2006		2005	
	(MMcf/d)	***(% of Total)***	*(MMcf/d)*	*(% of Total)*
Sales to aggregators				
ProGas Limited	**30**	**4**	38	5
Cargill Incorporated	**18**	**3**	20	2
Canwest Gas Supply Inc.	-	-	14	2
Others	**4**	**-**	3	-
Total sales to aggregators	**52**	**7**	75	9
Direct sales				
Alberta	**228**	**32**	286	35
U.S. Midwest	**159**	**22**	160	20
British Columbia and U.S. Pacific Northwest	**84**	**12**	112	14
California	**43**	**6**	45	6
U.S. Rockies	**43**	**6**	41	5
Eastern Canada	**19**	**3**	12	1
Saskatchewan	**7**	**1**	7	1
Total before internal sales	**583**	**82**	663	82
Sales within Petro-Canada	**81**	**11**	75	9
Total direct sales	**664**	**93**	738	91
Total sales	**716**	**100**	813	100

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 (2% of estimated 2007 natural gas production in Western Canada) has been sold, at an average plant gate netback price of $3.48/Mcf. In 2008, the volume of natural gas sold under these fixed-price contracts is expected to remain at 10 MMcf/d, at an average plant gate netback price of $3.62/Mcf.

Royalty Regime

The royalty regimes are a significant factor in the profitability of crude oil and natural gas production. In Western Canada, 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 the U.S., production is from federal, state and freehold lands. Production from federal and state lands is subject to a fixed royalty rate plus a payment to the landowner. Freehold royalty rates are determined by negotiations with the freehold land owner. In 2006, Petro-Canada's average royalty rate for North American Natural Gas was approximately 21% for conventional crude oil, NGL and natural gas.

Mackenzie Delta/Corridor, Northwest Territories

With interests in eight exploration blocks covering approximately 1.2 million acres gross (870,000 net acres), Petro-Canada is a significant leaseholder in the Mackenzie Delta/Corridor. During 2005, Petro-Canada acquired two exploration licences covering 411,471 acres, with work commitment bids totalling approximately $35 million. Petro-Canada's holdings are comprised of six exploration licences and two Inuvialuit land concessions. Petro-Canada is the operator of five of the licences. The net work commitments on the licences total approximately $58 million and are guaranteed by performance bonds for the Company's net share of approximately $14 million. Work program terms in the Inuvialuit land concessions include seismic acquisition and drilling. In 2002, a natural gas discovery at the Tuk M-18 well tested at restricted rates of up to 30 MMcf/d. Petro-Canada also holds a 100% position in 73,000 acres covering two Significant Discovery Areas (SDAs) in the Colville Hills area of the Mackenzie Delta/Corridor. The M-47 well on the Tweed Lake SDA was re-entered and tested in 2004, with restricted rates up to 10 MMcf/d. Having secured what it believes to be the area's most prospective acreage for future exploration, Petro-Canada will pace activities pending the anticipated approval and construction timeline for the Mackenzie pipeline.

Alaska

Petro-Canada's initial foray into Alaska was in the Foothills area north of the Brooks Mountain Range. Field geological studies have confirmed that the geology and prospectivity of this area are similar to the Alberta Foothills, where Petro-Canada has developed considerable expertise and has had significant success finding natural gas. In 2005, Petro-Canada and Anadarko Petroleum Corporation formed a 50/50 Foothills joint venture through various transactions and, by January 2006, jointly held 2.5 million gross acres of leased and option lands in the Alaska Foothills. BG (Alaska) E&P Inc. became a third equal participant in the joint venture early in 2006. At state and federal lease sales in 2006, this group was a successful bidder on about 412,000 gross acres in the area (a portion of this acreage remains subject to state title verification), giving each company a net land position in the Alaska Foothills of approximately one million acres, including option acreage. While it is unlikely the region will be serviced by a pipeline for some time, this acreage is close to a proposed pipeline route to southern markets.

In 2004, Petro-Canada acquired a large position (322,610 gross and net acres) in the NW National Petroleum Reserve-Alaska (NPR-A), an area of significant potential for large oil prospects. Petro-Canada and FEX L.P. (a subsidiary of Talisman Energy Inc.) reached a pooling agreement for the joint exploration of selected leases in the NPR-A in early 2006. As a result of this agreement, Petro-Canada obtained a 30% interest in the Aklaq-2 exploration well. It was drilled in the first quarter of 2006 and found to have hydrocarbons in quantities that were not commercially economical. In the latter part of 2006, FEX and Petro-Canada acquired 48 leases, or 562,000 gross acres, at the NPR-A lease sale for $10.4 million US and subsequently pooled the majority of their NPR-A leaseholdings, covering approximately 1.2 million acres. As a result, in jointly held NPR-A acreage with FEX, Petro-Canada's net acreage position is just over 500,000 acres.

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 July 2004, an MOU was signed with TransCanada PipeLines to develop and share (50/50) ownership of an LNG facility at Gros-Cacouna, Quebec. The proposed facility will receive, store and re-gasify imported LNG. Petro-Canada will have throughput and marketing rights to 100% of the send-out capacity of approximately 500 MMcf/d of natural gas.

The partners continued to advance the proposed LNG import and re-gasification terminal at Gros-Cacouna, Quebec, with a joint filing of an Environmental Impact Assessment with the provincial and federal governments in the second quarter of 2005. A joint provincial and federal government public review and consultation process took place in 2006. The Company, along with its partner, TransCanada PipeLines, is aiming to secure regulatory approval in 2007.

Link to Petro-Canada's Corporate and Strategic Priorities

The North American Natural Gas business is aligned with Petro-Canada's strategic priorities as outlined by its progress in 2006 and goals for 2007.

	2006 RESULTS	2007 GOALS
DELIVERING PROFITABLE GROWTH WITH A FOCUS ON OPERATED, LONG-LIFE ASSETS	• drilled 393 gross wells in Western Canada, including 291 wells in the Medicine Hat region[1] • drilled more than 280 gross wells, added 50,000 net acres of tight gas prone land and continued to increase CBM well de-watering in the U.S. Rockies • completed regulatory hearing for the LNG facility at Gros-Cacouna • increased land position in Alaska to 1.5 million net acres of leased and option lands	• transition further into unconventional gas plays • optimize opportunities around core assets • double U.S. Rockies production to 100 MMcfe/d by year-end 2007 • shift focus from developing around existing production to exploring in new areas • receive regulatory decision for the LNG facility at Gros-Cacouna • advance exploration prospects in the Mackenzie Delta/Corridor and Alaska
DRIVING FOR FIRST QUARTILE[2] OPERATION OF OUR ASSETS	• achieved better than 98% reliability at Western Canada facilities • successfully conducted major turnaround at the Hanlan gas plant, with no air licence exceedances	• sustain reliability performance • continue to leverage costs through strategic alliances and preferred suppliers
CONTINUING TO WORK AT BEING A RESPONSIBLE COMPANY	• achieved record total recordable injury frequency (TRIF) in Western Canada, a 40% decrease compared with 2005 • improved employee and contractor safety culture through behaviour-based safety programs • proactively remediated and reclaimed old sites • achieved record low regulatory compliance exceedances	• continue to focus on TRIF and maintain low regulatory exceedances • complete the roll out of behaviour-based safety for employees and contractors • drive for continuous improvement in contractor safety performance • proactively remediate and reclaim old sites

1 Includes wells only where Petro-Canada has a working interest.
2 References to first quartile operations in this AIF do not refer to industry-wide benchmarks or externally recognized measures. The Company has a variety of internal metrics which define and track first quartile operational performance.

East Coast Oil

Business Summary and Strategy

Petro-Canada is positioned in every major oil development off Canada's East Coast. The Company holds a 20% interest in Hibernia and a 27.5% interest in White Rose, and is the operator with a 34% interest in Terra Nova.

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 operating performance
- sustaining profitable production through reservoir extensions and add-ons
- pursuing high potential development projects

In 2006, realized crude oil prices remained strong, while production decreased due to the early shutdown and planned dry dock turnaround of the Terra Nova FPSO. East Coast Oil realized crude prices averaged $71.12/bbl in 2006, up from $63.15/bbl in 2005. Petro-Canada's share of east coast oil production averaged 72,700 b/d in 2006, down from 75,300 b/d in 2005. Lower Terra Nova production was partially offset by the addition of White Rose production. East Coast Oil operating and overhead costs averaged $7.71/bbl in 2006, compared with $4.52/bbl in 2005. Operating costs for East Coast Oil increased as a result of the Terra Nova turnaround, excluding insurance premium surcharges and startup costs for White Rose.

Hibernia

The Hibernia oilfield is approximately 315 kilometres southeast of St. John's, Newfoundland and Labrador. The production system used is a fixed Gravity Base Structure (GBS), which sits on the sea floor. The GBS has a production capacity of 230,000 b/d gross and storage capacity of 1.3 MMbbls gross; however, actual production levels are lower, reflecting current reservoir capability. It commenced production in November 1997. The Hibernia oilfield, encompassing the Hibernia and Ben Nevis Avalon reservoirs, is estimated to have a remaining production life of 20 to 23 years. The development potential of the Ben Nevis Avalon and Southern Extension of the Hibernia reservoir remains under assessment. In 2006, the operator submitted a development plan to the regulator for the Hibernia South Extension. In early 2007, the Government of Newfoundland and Labrador rejected the decision report of the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) to approve the development of the Hibernia Southern Extension and asked the applicants for additional information. Petro-Canada and its partners in the Hibernia project are reviewing the decision.

At December 31, 2006, there were 28 producing oil wells, 15 water injection wells and seven gas injection wells in operation. Field production is transported by shuttle tanker either from the platform to a transshipment terminal on the Avalon Peninsula or, if tanker schedules permit, directly to market. Crude oil delivered to the transshipment 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 transshipment facility.

Hibernia production averaged 178,500 b/d gross (35,700 b/d net) in 2006, down from 199,000 b/d gross (39,800 b/d net) in 2005. The Hibernia platform continued to operate at first quartile levels during 2006, with lower production reflecting normal reservoir decline rates. Early in 2007, Hibernia encountered a mechanical failure on one of the platform’s main power generators, thereby reducing production. While repairs are being completed, it is expected that Hibernia production will be in the range of 100,000 b/d to 110,000 b/d gross (20,000 b/d to 22,000 b/d net) for January and part of February 2007. To mitigate the impact of the main power generator repair on production, the operator advanced the planned third quarter turnaround. The planned Hibernia 30-day turnaround is expected to start in mid-February 2007.

Terra Nova

The Terra Nova oilfield, which is approximately 350 kilometres southeast of St. John's, Newfoundland and Labrador, was discovered by Petro-Canada in 1984. Located about 35 kilometres southeast of Hibernia, it is the second oilfield to be developed offshore Newfoundland and Labrador. The production system uses a FPSO vessel, which is a ship moored on location. Terra Nova was the first harsh environment development in North America to use an FPSO vessel. It has a production capacity of 180,000 b/d gross and a storage capacity of 960,000 barrels gross; however, actual production levels reflect current reservoir capability. Production from the Terra Nova oilfield began in January 2002. The field is estimated to have a remaining production life of approximately 13 to 16 years.

At year-end 2006, 15 producing oil wells, nine water injection wells and three gas injection wells were in operation. Terra Nova uses the same system of shuttle tankers and a transshipment terminal that is currently used for Hibernia, and also transports its crude oil to markets in Eastern Canada and the U.S.

At Terra Nova, production averaged 37,600 b/d gross (12,800 b/d net), down considerably from 99,100 b/d gross (33,700 b/d net) in 2005. Early in 2006, the first production well came on-stream in the Far East Block of the Terra Nova field. Terra Nova had a challenging year when its planned maintenance turnaround was advanced following the mechanical failure of the second of two main power generators. The completion of regulatory inspections and reliability improvements was expected to last up to 90 days, but was extended to complete necessary work. The reliability work included a 50% increase in onboard living quarters to support increased routine maintenance, repairs to gearboxes attached to two power generators and improvements to the gas compression system. In November, oil production from the Terra Nova field resumed. Petro-Canada's share of the total cost of the turnaround was approximately $77 million.

In December 2006, the Terra Nova FPSO encountered a mechanical issue in a swivel on the turret system that supports water injection to the reservoir. During the water injection outage, production was reduced to an average of 90,000 b/d gross (30,600 b/d net). A temporary fix was completed in late December and production returned to normal rates in excess of 100,000 b/d gross (34,000 b/d net). Full repair of the swivel requires dismantling and reassembly of the upper turret. This work is currently planned for completion during a turnaround in the summer of 2008.

White Rose

White Rose, the third development offshore Newfoundland and Labrador, is about 350 kilometres southeast of St. John's and approximately 50 kilometres northeast of Hibernia and Terra Nova. It also uses an FPSO vessel similar to Terra Nova. The vessel has a design production capacity of 100,000 b/d gross and a storage capacity of 940,000 barrels gross. Production is offloaded to chartered tankers that go directly to markets in Eastern Canada and the U.S. Production from the White Rose oilfield began in November 2005. The field is estimated to have a remaining production life of approximately 12 to 15 years.

At year-end 2006, six producing oil wells and eight water injection wells were in operation. Development plans for White Rose include the drilling of 18 to 19 wells. During 2006, the fourth, fifth and sixth production wells were completed. White Rose operated reliably in 2006, ramping up production to average 88,000 b/d gross (24,200 b/d net) compared with 6,500 b/d gross (1,800 b/d net) in 2005. The 2006 results reflected a full year of operation at White Rose.

In 2006, the West White Rose 0-28 and North Amethyst K-15 delineation wells were drilled in the west and southwest sections of the White Rose field, respectively. The White Rose 0-28 well revealed a 280-metre oil column in a multi-layered reservoir and the White Rose North Amethyst K-15 well revealed a 50- to 55-metre oil column in the Ben Nevis Avalon formation with high reservoir quality.

Offshore Oil Royalty Regime

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 which are 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 has been reached, including a specified return allowance, 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. As expected, royalty payments at Terra Nova increased in the fourth quarter of 2005 from 5% of gross revenues to a range of 27% to 29% of gross revenues. The royalty regime allows for large expenditures, such as the 2006 turnaround, to be applied against revenue. Because of this, it is forecasted that Terra Nova will incur a 5% basic royalty on gross revenue for the first quarter of 2007, and will return to a 30% of net revenue royalty for the balance of 2007. Terra Nova royalty payments are expected to average between 20% and 25% of gross revenues in 2007.

In July 2003, the Government of Newfoundland and Labrador published 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 applies to the White Rose development. It is expected that White Rose will reach tier one royalty payout in the fourth quarter of 2007, at which time the royalty rate will shift to 20% of net revenue from 5% of gross revenue. The total royalty payable in 2007 is expected to equate to a rate of between 4% and 8% of gross revenue, depending on crude oil prices.

Other Offshore Exploration and Development

In addition to existing East Coast Oil developments, Petro-Canada holds interests in a number of discoveries, including a 23.9% interest in the Hebron/Ben Nevis oilfield discoveries. In 2005, Chevron (as operator), Petro-Canada and the other joint venture participants signed a unitization and joint operating agreement to advance the joint evaluation of the Hebron/Ben Nevis and West Ben Nevis oilfields offshore Newfoundland and Labrador. In April 2006, Petro-Canada and its partners in the Hebron development suspended negotiations with the Government of Newfoundland and Labrador and demobilized the Hebron project team after failing to reach a development agreement. Petro-Canada continues to consider Hebron a high quality asset. While project activities have been suspended at this time, Petro-Canada and its project partners remain optimistic that the project could proceed at a future date with the conclusion of a definitive agreement with the provincial government.

Link to Petro-Canada's Corporate and Strategic Priorities

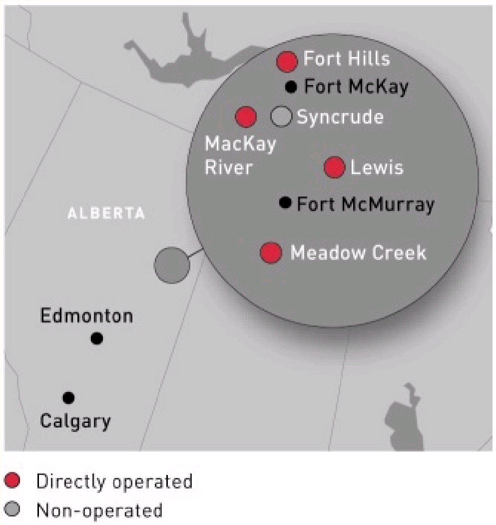
The East Coast Oil business is aligned with Petro-Canada's strategic priorities as outlined by its progress in 2006 and goals for 2007.

	2006 RESULTS	2007 GOALS
DELIVERING PROFITABLE GROWTH WITH A FOCUS ON OPERATED, LONG-LIFE ASSETS	• ramped up White Rose production averaging 88,000 b/d gross (24,200 b/d net) • completed drilling the West White Rose 0-28 and North Amethyst K-15 delineation wells at White Rose	• increase reliability at Terra Nova • advance in-field Hibernia growth prospects • delineate West White Rose • advance development plans for South White Rose Extension, North Amethyst and West White Rose prospects
DRIVING FOR FIRST QUARTILE OPERATION OF OUR ASSETS	• completed Terra Nova turnaround for regulatory compliance and to improve reliability • saw operating and overhead costs increase, reflecting turnaround costs at Terra Nova	• conduct a 30-day turnaround scheduled at Hibernia for regulatory compliance • receive regulatory approval to increase annual production from SeaRose FPSO at White Rose • complete 16-day turnaround at White Rose
CONTINUING TO WORK AT BEING A RESPONSIBLE COMPANY	• saw 28% decrease in TRIF, compared with 2005 • accepted responsibility for an improper discharge of oil from Terra Nova in 2004, contributing $220,000 of the $290,000 fine to positive environmental projects • improved the produced water system on Terra Nova, resulting in no regulatory compliance exceedances	• further reduce TRIF • apply lessons learned from oily water discharge to prevent future incidents • maintain zero regulatory exceedances

In 2007, Petro-Canada is consolidating its East Coast Oil and International businesses. The purpose of the consolidation is to leverage and grow the capabilities of similar operations.

Oil Sands

Business Summary and Strategy



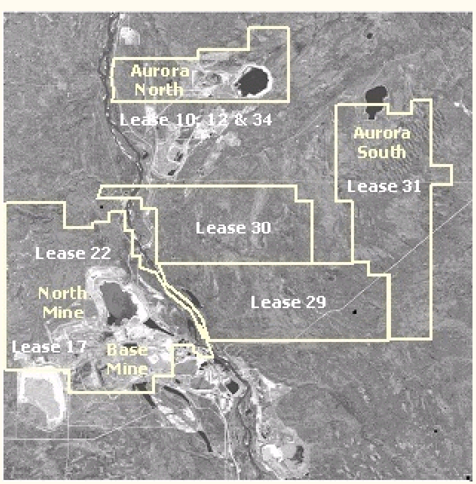
Petro-Canada has more than 10 billion barrels of Oil Sands total resource. The Company's major Oil Sands interests include a 12% ownership in the Syncrude joint venture (an oil sands mining operation and upgrading facility), 100% ownership of the MacKay River *in situ* bitumen development (a steam-assisted gravity drainage (SAGD) operation), a 55% ownership in and operatorship of the proposed Fort Hills oil sands mining and upgrading project, and extensive oil sands acreage 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 create value
- a staged approach to development of capital-intensive Oil Sands projects to allow rigorous cost management and the opportunity to benefit from evolving technology

The Company has chosen to participate in the full oil sands value chain due to its resource potential and strong position with bitumen upgrading capacity. Petro-Canada not only has processing capacity through Syncrude and Suncor Energy Inc. (starting in 2008), but the Company is also converting the conventional crude oil train at its Edmonton refinery to refine bitumen-based feedstock from northern Alberta, starting in 2008. This conversion, along with the existing synthetic crude train, will result in the refinery running on an exclusive diet of bitumen-based feedstock. This connection between resource and upgrading capacity should provide more economic certainty in a business where volatile light/heavy differentials affect bitumen pricing.

Oil Sands Mining - Syncrude



Petro-Canada has a 12% interest in Syncrude, the world's largest oil sands mining operation, located approximately 40 kilometres north of Fort McMurray, Alberta. Syncrude is a joint venture formed to mine shallow deposits of oil sands from the McMurray formation in the Athabasca Oil Sands, and to extract and upgrade bitumen to produce synthetic crude oil. Syncrude is readily accessible by public roads.

Syncrude holds eight oil sands leases (numbered 10, 12, 17, 22, 29, 30, 31 and 34) issued by the Province of Alberta, covering a total of approximately 255,000 acres. The operating licence associated with these leases expires in 2035. The licence permits Syncrude to mine oil sands and produce synthetic crude oil from approved development areas on the oil sands leases. The leases are automatically renewable as long as oil sands operations are ongoing or the leases are part of an approved development plan. All eight leases are included in a development plan approved by the Alberta Energy and Utilities Board. There were no known commercial operations on these leases prior to the startup of Syncrude operations in 1978.

Design engineering on the Syncrude project commenced in 1972. Alberta government approvals were received in 1973. Site preparation and construction continued from 1973 to 1978. Commercial operations commenced in 1978. A $1.2 billion capacity addition project was undertaken from 1984 to 1988. The first two stages of the Syncrude 21 expansion projects were completed in 1997 and 2001, respectively. The $470 million Stage I project comprised expansions of the north mine and an upgrader de-bottleneck. The $1 billion Stage II project consisted of the opening of the Aurora mine and a further upgrader de-bottleneck. The $8.2 billion Stage III project involved the opening of a second Aurora mine and an upgrading expansion. Following a brief run in May, Syncrude initiated bitumen feed into its new Coker 8-3 in August 2006, enabling the Stage III expansion to come online and begin ramping up production. Syncrude's Stage III expansion will increase Petro-Canada's share of production capacity to approximately 42,000 b/d. Production is expected to reach this level following a ramp up period of one to two years.

PROVED RESERVES - SYNTHETIC CRUDE OIL
Working Interest Before Royalties

(MMbbls)	**Base Mine and North Mine**[1]	**Aurora**[2]	**Total**
Beginning of year 2005	**109**	**222**	**331**
Revision of previous estimates	–	20	20
Extensions and discoveries	–	–	–
Production, net	(4)	(5)	(9)
End of year 2005	**105**	**237**	**342**
Revision of previous estimates	–	14	14
Extensions and discoveries	–	–	–
Production, net	(5)	(6)	(11)
End of year 2006	**100**	**245**	**345**

1 Leases 17 and 22.
2 Leases 10, 12, 31 and 34.

Syncrude has an estimated remaining proved and probable reserves life index in excess of 50 years. Proved reserves of 30 degree synthetic crude oil from Syncrude are based on high geological certainty and the application of proven technology. Drill-hole spacing is less than 500 metres, and appropriate co-owner and regulatory approvals are in place. For probable reserves, drill-hole spacing is less than 1,000 metres and reserves are included in the 50-year long-range lease development plan. In 2006, approximately 398 million tons of oil sands produced 112 MMbbls of bitumen that was upgraded into 94 MMbbls of synthetic crude oil.

Three mines, the Base mine, the North mine and the Aurora mine, are currently in operation at Syncrude. Base mine operations will be discontinued in 2007. Mine operations are carried out using truck, shovel and hydro-transport systems. An extraction process recovers about 90% of the crude bitumen contained in the mined sands. Refining processes upgrade the bitumen into high quality, light (30 degree) sweet synthetic crude oil, with a process yield of approximately 85%. Syncrude's synthetic crude oil production is processed at refineries in Edmonton, Alberta, in Eastern Canada and the U.S.

Two electricity generating plants located on site and owned by the Syncrude joint venture partners provide power for Syncrude. One plant produces a maximum of 270 megawatts (MW), the other produces 80 MW.

Syncrude's production and unit operating costs were positively affected by the startup of the Stage III expansion in 2006. Syncrude's production averaged 258,300 b/d gross (31,000 b/d net) in 2006, compared with 214,200 b/d gross (25,700 b/d net) in 2005. Average unit operating and overhead costs decreased to $30/bbl in 2006, down from $31.90/bbl in 2005. Lower unit operating costs were mainly due to higher production and lower natural gas costs, partially offset by Syncrude retention and incentive-based compensation. Syncrude realized price for synthetic crude oil averaged $72.13/bbl in 2006, up from $70.41/bbl in 2005.

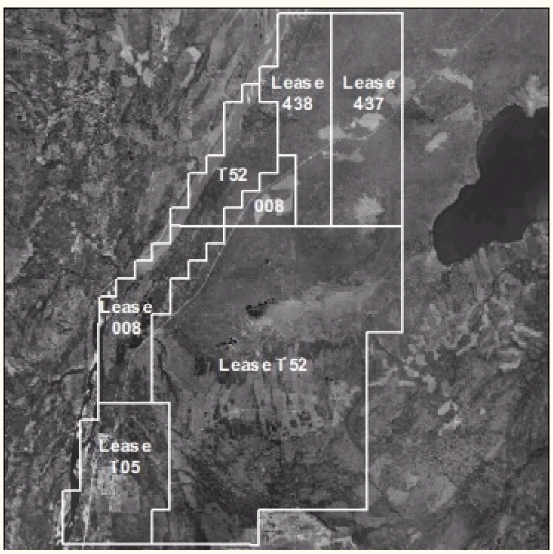
SYNCRUDE MINING STATISTICS

	2006	2005	2004
Total Mined Volume[1]			
Millions of tons	**398.0**	324.0	353.2
Mined volume of oil sands ratio	**2.3**	2.1	2.1
Oil Sands Processed			
Millions of tons	**175.0**	152.6	170.9
Average bitumen grade *(weight %)*	**11.3**	11.1	11.1
Bitumen in Mined Oil Sands			
Millions of tons	**19.6**	16.9	19.0
Average extraction recovery *(%)*	**90.3**	89.2	87.3
Bitumen Production[2]			
Millions of barrels	**111.5**	94.2	103.2
Average upgrading yield *(%)*	**84.9**	85.3	85.5
Gross Synthetic Crude Oil Shipped[3]			
Millions of barrels	**94.3**	78.1	87.2
Petro-Canada's Share of Marketable Crude Oil			
Millions of bbls before royalties	**11.3**	9.4	10.5
Millions of bbls after royalties	**10.2**	9.3	10.4

1 Includes pre-stripping of mine areas and reclamation volumes.
2 Bitumen production in barrels is determined by multiplying the mined bitumen volume in tons by the average extraction recovery and then applying the appropriate conversion factor.
3 In 2006, 1.35% of the produced synthetic crude oil was used internally at Syncrude with the remainder sold externally. In 2004 and 2005, the internal use was 1.30% and 1.46%, respectively.

In November 2006, Syncrude entered into a Management Services agreement with Imperial Oil Resources for the receipt of operational, technical and business services.

Fort Hills Project



In 2005, Petro-Canada strengthened its position in oil sands mining by securing the majority interest and operatorship of the Fort Hills project from UTS. Later in 2005, a mining partner, Teck Cominco, joined the consortium. Petro-Canada is project operator with a 55% interest, UTS has a 30% interest and Teck Cominco holds a 15% interest. Petro-Canada plans to market 100% of the production from Fort Hills. The Fort Hills oil sands mining and upgrading project has leases estimated to contain approximately 4 billion barrels to 5 billion barrels of bitumen resource (approximately 2.2 billion barrels to 2.8 billion barrels net to Petro-Canada), which will be recovered over a 30- to 40-year period. The project has received regulatory approval to produce up to 190,000 b/d gross (104,500 b/d net) of bitumen from the mine.

In early 2006, the Fort Hills partners acquired two additional leases adjacent to the existing Fort Hills leases to afford greater mine planning flexibility. The initial phase of mine production is expected to be in the range of 100,000 b/d to 170,000 b/d gross (55,000 b/d to 93,500 b/d net) of bitumen. The partners selected Sturgeon County, 40 kilometres northeast of Edmonton, as the location for the upgrading facility to process bitumen from the Fort Hills mine. The upgrader is expected to use delayed coking technology to convert Fort Hills bitumen into light synthetic crude oil. The initial phase of the upgrader is expected to be in the range of 85,000 b/d to 145,000 b/d gross (46,750 b/d to 79,750 b/d net). Late in 2006, Petro-Canada filed the commercial application for the Sturgeon Upgrader and expects to receive regulatory approval in 2008. First bitumen production is expected in the 2011 time frame. The Company plans to complete the design basis memorandum (DBM) and preliminary cost estimates for the project in the first half of 2007.

The Fort Hills Partnership has agreed with Alberta Energy to several development milestones for the Fort Hills oil sands project, including a production milestone requiring a mine be completed and producing 100,000 b/d gross (55,000 b/d net) of bitumen by mid-2011. In the event that the development milestones are not met, Alberta Energy may impose a performance deposit or cancel certain leases in connection with Fort Hills.

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 uses 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 is expected to 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, respectively. Well pairs are about 700 metres to 750 metres in length and produce 800 b/d to 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. Work to tie in a third well pad, which includes 14 horizontal well pairs, was completed and, in January 2006, the new well pad began steaming. Production from the new well pad commenced in the second quarter of 2006 and continues to ramp up. In 2007, work to de-bottleneck water handling capacity and add production from a fourth well pad is expected to enable MacKay River to reach plateau production of 27,000 b/d to 30,000 b/d.

MacKay River's production remained flat and unit operating costs increased slightly in 2006. Production averaged 21,200 b/d in 2006, consistent with an average of 21,300 b/d in 2005, as natural declines were offset by production from the third well pad. MacKay River reliability averaged 92% in 2006, down from 98% in 2005, reflecting a gearbox failure in April. Unit operating and overhead costs increased by 5% in 2006, averaging $17.83/bbl, compared with $17.06/bbl in 2005. Higher unit operating costs were due to higher costs for goods and services, partially offset by lower natural gas costs. MacKay River realized price for bitumen averaged $28.93/bbl in 2006, compared with $18.53/bbl in 2005.

In 2005, Petro-Canada filed an application for a potential MacKay River *in situ* expansion project with first production by the end of the decade and peak production of an additional 40,000 b/d to follow. Petro-Canada also acquired the Dover UTF and oil sands leases adjacent to the MacKay River development in 2005. In the third quarter of 2006, the Company purchased, for $30 million, 13 additional oil sands leases, comprising a total of 31,232 hectares immediately adjacent to Petro-Canada's existing *in situ* development at MacKay River. The new leases provide additional SAGD development potential.

In the fourth quarter of 2006, the Company announced its intention to divest its interest in the five *in situ* properties of Chard, Stony Mountain, Liege, Thornbury and Ipiatik. The sale process attracted considerable attention; however, the bids received did not meet Petro-Canada's expectations; therefore, the Company will not divest its interests at this time.

Royalty Regime

During 2001, Syncrude completed the transition from a project-specific contractual royalty to the 1997 Province of Alberta Oil Sands Royalty Regulation. Effective in 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 allowable operating and capital costs from gross revenue. Syncrude reached royalty payout in the second quarter of 2006 and shifted to a royalty rate of 25% of net operating revenues from 1% of gross revenues. The total royalty paid in 2006 equated to a rate of 10% of gross revenues. The total royalty payable in 2007 is expected to equate to a rate of between 10% and 15% of gross revenue, depending on crude oil prices.

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 allowable operating and capital costs from gross revenue.

Integrated Oil Sands Development

At the Edmonton refinery, Petro-Canada is investing to convert the facility to run bitumen-based feedstock exclusively and to produce low-sulphur products. By mid-2008, an anticipated capital investment of $2 billion is expected to expand coker capacity, add new crude and vacuum units, increase sulphur plants and expand utilities. Costs based on the completion of preliminary engineering have increased from the original conceptual estimate of $1.2 billion. The increase reflects a more current assessment of refinery integration requirements and industry-wide cost pressures. Project economics remain strong as projected light/heavy crude differentials are expected to offset the increase in capital.

It is anticipated that the refinery conversion program 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 Company's long-term strategy and builds on a $1.4 billion investment in gasoline and diesel desulphurization.

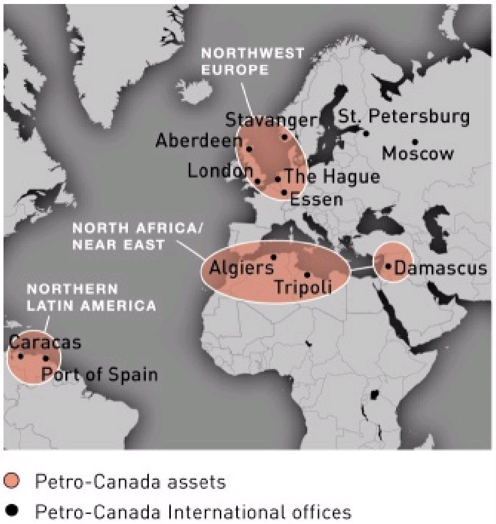
Link to Petro-Canada's Corporate and Strategic Priorities

The Oil Sands business is aligned with Petro-Canada's strategic priorities as outlined by its progress in 2006 and goals for 2007.

	2006 RESULTS	2007 GOALS
DELIVERING PROFITABLE GROWTH WITH A FOCUS ON OPERATED, LONG-LIFE ASSETS	• selected Sturgeon County for Fort Hills upgrader location • submitted commercial application for Sturgeon Upgrader • acquired additional oil sands leases adjacent to MacKay River and the existing Fort Hills leases • Syncrude Stage III expansion came on-stream	• complete Fort Hills DBM and initial cost estimate, and initiate front-end engineering and design (FEED) • receive regulatory decision on MacKay River expansion project • continue ramp up of Syncrude Stage III expansion • complete MacKay River water handling capacity upgrade and tie in a fourth well pad so that production can increase in 2008
DRIVING FOR FIRST QUARTILE OPERATION OF OUR ASSETS	• saw Syncrude non-fuel unit operating costs decrease by 5%, compared with 2005 • saw MacKay River unit operating costs increase by 5%, compared with 2005, reflecting the Alberta business environment • saw Syncrude enter into a Management Services agreement with Imperial Oil Resources for operational, technical and business services • maintained reliability at MacKay River at 92%	• decrease MacKay River non-fuel unit operating costs by 10%, compared with 2006 • decrease Syncrude non-fuel unit operating costs by 10%, compared with 2006 • sustain MacKay River reliability at greater than 90%
CONTINUING TO WORK AT BEING A RESPONSIBLE COMPANY	• TRIF decreased by 46%, compared with 2005	• maintain focus on TLM and Zero-Harm • ensure regulators, First Nations and other key stakeholders affected by major projects are properly consulted and engaged

International

Business Summary and Strategy



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, with exploration activities extending into Denmark and Norway. The North Africa/Near East region provides crude oil production from assets in Libya, with exploration activity extending into Syria, Algeria, Tunisia and Morocco. In addition, a natural gas development is underway in Syria. In Northern Latin America, operations are focused in Trinidad and Tobago, and Venezuela.

The International strategy is to access a sizable resource base using a three-fold approach to:

- optimize and leverage existing assets
- seek out new, long-life opportunities
- execute a substantial and balanced exploration program

International production from continuing operations averaged 103,600 barrels of oil equivalent per day (boe/d) net in 2006, compared with 106,300 boe/d net in 2005. The decrease was primarily due to lower production in Northwest Europe and Northern Latin America. International crude oil and liquids realized prices from continuing operations averaged $72.69/bbl and natural gas realized prices averaged $7.64/Mcf in 2006, compared with $65.93/bbl and $7.13/Mcf, respectively, in 2005. Operating and overhead costs from continuing operations averaged $7.61/boe in 2006, flat compared with $7.60/boe in 2005.

In 2005, Petro-Canada reached an agreement to sell the Company's mature producing assets in Syria. The sale was closed on January 31, 2006. These assets and associated results are reported as discontinued operations and excluded from continuing operations.

Northwest Europe

Production in Northwest Europe comes from the U.K. and the Netherlands sectors of the North Sea, with exploration activities extending into Denmark and Norway.

Petro-Canada's Northwest Europe production averaged 43,700 boe/d net in 2006, compared with 44,600 boe/d net in 2005. Natural declines in the U.K. and the Netherlands sectors of the North Sea were partially offset by new production from De Ruyter and L5b-C. Northwest Europe crude oil and liquids realized prices averaged $72.67/bbl and natural gas averaged $8.91/Mcf in 2006, compared with $66.13/bbl and $7.35/Mcf, respectively, in 2005.

In the central North Sea, the Company's interests are centred on the Triton development area, which is comprised of the joint development of the Guillemot West and Northwest fields, the Bittern field and the Clapham field. The Pict field, which achieved first oil in June 2005, also produces through the Triton area facilities. The Pict field produced an average of 10,460 boe/d in 2006. The 100% Petro-Canada owned and operated Saxon discovery, a Pict look-alike, advanced in 2006. The proposed development will be tied back to the Triton area infrastructure and is expected to come on-stream by the end of 2007. Saxon peak production is expected to be 7,000 boe/d. The crude oil gathered at Triton is shipped via tanker, while gas is delivered through the SEGAL system to the U.K. Petro-Canada is a 33.1% owner of the Triton FPSO.

In the Outer Moray Firth, the Company has a 29.9% interest in the Buzzard oilfield. The Buzzard field achieved first oil in January 2007. The field is expected to ramp up to peak production around the middle of 2007. The field is supported with three bridge-linked platforms supporting the wellhead facilities, the production facilities, living quarters and the utilities. Crude oil is transported via the Forties pipeline system to shore, and natural gas is transported to the St. Fergus gas terminal in Scotland via the U.K. Frigg pipeline. When the Company acquired its interest in the Buzzard field in June 2004, the purchase also included nearby blocks with exploration potential. This included Block 20/1 North where the non-operated Golden Eagle discovery was drilled in late 2006. The Company has a 25% working interest in this licence and work is ongoing to assess possible development.

Following the discovery on the Petro-Canada operated 13/27a Block (90% working interest) in 2005, the Company farmed into adjacent Blocks 13/26a and 13/26b in September 2006, obtaining a 27.5% non-operated working interest. Appraisal drilling is planned by the operator for the second half of 2007 to test the extent of the 13/27a discovery. In early 2007, Petro-Canada was awarded Block 13/24d, near Buzzard, in the U.K. 24th licensing round. The Company is operator with a 90% working interest.

Also 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 tie-back 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 Netherlands sector of the North Sea, oil production comes from the Petro-Canada operated Hanze and De Ruyter platforms. The Company has a 45% working interest in Hanze and a 54.07% working interest in De Ruyter. De Ruyter came on-stream in late September, delivering 5,500 boe/d gross (2,970 boe/d net) in 2006. De Ruyter is expected to add around 18,500 boe/d gross (10,000 boe/d net) in 2007. Oil from the Hanze and De Ruyter platforms is exported by dedicated tanker, with the cargoes marketed on a spot basis into Northwest Europe. Natural gas production from Hanze is exported to shore via the Northern Offshore Gas Transport (NOGAT) pipeline, and natural gas from De Ruyter is exported via the Noord Gas Transport (NGT) pipeline system. Two offshore exploration wells near the De Ruyter field are planned in 2007.

The major source of natural gas production in the Netherlands is from the L5b-L8b non-operated gas area where Petro-Canada has around a 30% working interest. L5b-C, a non-operated asset in this area, achieved first natural gas in November 2006. The Company has a 30% working interest in L5b-C, which is expected to add 10,000 boe/d gross (3,000 boe/d net) in 2007. The produced natural gas is transported to shore by pipeline and sold to NV Nederlandse Gasunie under long-term delivery and off-take contracts. Petro-Canada also holds a 12% interest in the onshore Bergen gas storage facility operated by BP p.l.c.

In 2006, Petro-Canada opened an office in Stavanger, Norway, following the award of five production licences in the Norwegian sector of the North Sea in the 2005 Awards in Predefined Areas (APA). In 2007, the Company was awarded seven additional production licences in the 2006 APA round. Petro-Canada is operator of four of the 12 licences.

Technical and commercial studies relating to development scenarios were undertaken on the Hejre field in Denmark in 2006. A non-operated licence (20% working interest) was acquired adjacent to the Hejre field as protection acreage for the discovery in 2006. The Stork and Robin prospects were drilled and completed as dry holes. This resulted in the Company's decision to relinquish the Robin licence in January 2007. The exploration period on the Svane discovery was extended by two years in 2006 to complete technical and economic re-evaluation.

North Africa/Near East

The core region of North Africa/Near East provides crude oil production from interests principally in Libya and a natural gas development in Syria is now underway.

In 2006, Petro-Canada's production from continuing operations in this region averaged 49,400 boe/d net, relatively unchanged from 49,800 boe/d net in 2005. North Africa/Near East crude oil and liquids realized prices from continuing operations averaged $72.70/bbl in 2006, compared with $65.79/bbl in 2005.

In Libya, Petro-Canada is one of the country's larger producers through its 49% interest in Veba Oil Operations (VOO), a joint venture with the National Oil Corporation of Libya (NOC). Production is high quality, low-sulphur (sweet) crude oil.

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. Because Libya is a member of OPEC, Libyan production has been constrained by OPEC quotas and may again be in the future.

In 2006, nine development wells were drilled in the producing fields in Libya, of which seven were completed. A further three exploration wells were drilled, with one new discovery on existing concessions. In 2007, Petro-Canada expects to participate in three exploration and appraisal wells with VOO. The Company was awarded an exploration licence in the Libyan third round EPSA IV auction. The onshore licence is located in the Sirte Basin and Petro-Canada is the operator with a 50% working interest.

Early in 2006, the Company completed the sale of its mature producing assets in Syria. In November, Petro-Canada acquired operatorship and a 90% interest in a Production-Sharing Contract (PSC) in the Ash Shaer and Cherrife natural gas fields for $54 million. Under the agreement, Petro-Canada expects to develop and produce an estimated 80 MMcf/d of natural gas, with first gas anticipated in 2010. In addition, preparations for drilling on Block II advanced with two exploration wells expected to be drilled in 2007.

In Algeria, Petro-Canada is the operator and has a 100% working interest in the Zotti Block. A well was spudded on the Block in late 2006.

In Tunisia during 2006, the Company closed its Tunis office and relinquished its 72.5% interest in the Melitta Block after completing its work commitment. In 2007, the Company intends to focus on exploration of the offshore, non-operated Cap Serrat and Bechateaur permits (33% working interest).

In Morocco, Petro-Canada extended its reconnaissance licence on the Bas Draa Block. A gravity magnetic survey will take place in the first half of 2007.

*Northern Lat*in America

In Northern Latin America, Petro-Canada's operations are focused in Trinidad and Tobago. The Company holds a 17.3% working interest in the North Coast Marine Area 1 (NCMA-1) offshore gas development project operated by BG Group p.l.c. In 2006, subsea tie-backs to the Hibiscus platform for Phases 3a and 3b were completed and first natural gas was achieved in late 2006. Phase 3c was approved and will involve development of the Poinsettia field with a platform and pipeline tie-back to the Hibiscus platform. Production is expected to come on-stream by early 2009. Natural gas 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 2006, Petro-Canada's share of Trinidad and Tobago production averaged 63 MMcf/d net, down from 72 MMcf/d net in 2005. This was due to a reduction in overall processing capacity at the Atlantic LNG plant, following maintenance on Trains 2 and 3 and delays in commissioning Train 4. Northern Latin America realized prices for natural gas averaged $5.13/Mcf in 2006, compared with $6.62/Mcf in 2005.

Petro-Canada signed PSCs with the Trinidad and Tobago Ministry of Energy and Energy Industries for offshore exploration Blocks 1a, 1b and 22 in 2005. These blocks cover a total of 4,258 square kilometres, with Block 1a containing four discoveries. In 2006, the 3D seismic program on Blocks 1a, 1b and 22 offshore Trinidad and Tobago were completed. Drilling plans are advancing for these Blocks with the purchase of long-lead materials, evaluation of seismic data and work to obtain environmental approvals. Rigs have been secured and drilling is expected to commence in the second half of 2007.

In Western Venezuela, Petro-Canada holds a 50% working interest in the La Ceiba Block that straddles the eastern shores of Lake Maracaibo. A declaration of commercial viability and a field development plan was filed for the La Ceiba development in 2005. The field development plan is awaiting approval by the Venezuelan authorities.

Business Development Opportunities

The Company continues with discussions to import natural gas from Russia to North America through a joint LNG project with Gazprom. The liquefaction plant, proposed in the St. Petersburg region, is expected to export 3.5 million tonnes to 5 million tonnes (500 MMcf/d to 700 MMcf/d) per annum of natural gas supplied from the Russian grid. An agreement was signed with Gazprom in March 2006 to proceed with the initial engineering design of the liquefaction plant. The preliminary engineering studies will provide cost and schedule estimates, from which the Company may proceed into detailed design and engineering for the liquefaction plant.

Link to Petro-Canada's Corporate and Strategic Priorities

The International business is aligned with Petro-Canada's strategic priorities as outlined by its progress in 2006 and goals for 2007.

	2006 RESULTS	2007 GOALS
DELIVERING PROFITABLE GROWTH WITH A FOCUS ON OPERATED, LONG-LIFE ASSETS	• achieved first production at De Ruyter and L5b-C • closed sale of mature Syrian producing assets • acquired 90% interest and became operator of the Ash Shaer and Cherrife gas project • secured drilling rigs for 2007 and 2008 exploration programs • awarded Sirte licence in Libyan third round EPSA IV auction	• ramp up Buzzard and L5b-C to full production • achieve first production at Saxon in the U.K. sector of the North Sea by year end • participate in up to a 17-well exploration drilling program, (depending on rig arrival dates) with balanced risk profile over the next 18 months • commence field appraisal and project design activities on Ash Shaer and Cherrife development • establish a Libyan exploration program on the newly acquired Sirte exploration block • actively pursue LNG supply opportunities
DRIVING FOR FIRST QUARTILE OPERATION OF OUR ASSETS	• achieved more than 95% uptime on Hanze platform • achieved full production capacity at De Ruyter platform ahead of schedule • seconded specialists to support Libyan operations • improved Scott platform reliability and uptime by 33%, compared with 2005	• maintain excellent reliability at De Ruyter platform • optimize production capacity on Triton area assets by implementing recommendations from de-bottlenecking study
CONTINUING TO WORK AT BEING A RESPONSIBLE COMPANY	• had nine recordable injuries in 2006, compared with 14 in 2005, but TRIF rose to 0.8 in 2006, compared with 0.62 in 2005, reflecting fewer person hours worked • achieved five years of continuous operations on the Hanze platform without a lost-time incident • provided safety training and equipment to fishermen in Trinidad and Tobago as part of community liaison activities during seismic operations	• maintain focus on TRIF and increase leadership visibility of Zero-Harm effort • reduce oil in produced water at Triton • collaborate with local stakeholders in Trinidad and Tobago to minimize impact of offshore drilling

Discontinued Operations

On January 31, 2006, Petro-Canada completed the sale of the Company's producing assets in Syria to a joint venture of companies owned by India's Oil and Natural Gas Corporation Limited and the China National Petroleum Corporation for net proceeds of $640 million. The sale resulted in a gain on disposal of $134 million recorded in the first quarter of 2006. This sale aligned with Petro-Canada's strategy to increase the proportion of long-life and operated assets within its portfolio. Petro-Canada's activities in Syria remain part of the North Africa/Near East producing region, with an active exploration program in Block II and the addition of the Ash Shaer and Cherrife natural gas projects in Syria during 2006. Additional information concerning Petro-Canada's discontinued operations can be found in Note 4 to the Consolidated Financial Statements.

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, NGL, BITUMEN, SYNTHETIC CRUDE OIL AND NATURAL GAS

	Years Ended December 31,					
	2006		2005		2004	
	Before Royalties	**After Royalties**	Before Royalties	After Royalties	Before Royalties	After Royalties
Crude oil and equivalents *(thousands of barrels/day - Mbbl/d)*						
East Coast Oil	**72.7**	**68.5**	75.3	69.6	78.2	75.1
Oil Sands[1]	**52.2**	**48.8**	47.0	46.5	45.2	44.8
North American Natural Gas	**14.2**	**10.8**	14.7	11.2	15.3	11.4
Northwest Europe	**33.2**	**33.2**	33.7	33.7	40.4	40.4
North Africa/Near East	**49.4**	**44.7**	49.8	44.0	50.9	43.7
Total crude oil and equivalents	**221.7**	**206.0**	220.5	205.0	230.0	215.4
Natural gas *(MMcf/d)*						
North American Natural Gas	**616**	**489**	668	512	695	530
Northwest Europe	**63**	**63**	66	66	85	85
Northern Latin America	**63**	**32**	72	29	72	51
Total natural gas	**742**	**584**	806	607	852	666
Total production from continuing operations[2] *(thousands of barrels of oil equivalent/day - Mboe/d)*	**345**	**303**	355	306	372	326
Discontinued operations						
Crude oil and NGL *(Mbbl/d)*	**5.2**	**1.4**	65.9	20.3	75.7	23.7
Natural gas *(MMcf/d)*	**2**	–	25	4	21	3
Total production from discontinued operations[2] *(Mboe/d)*	**6**	**1**	70	21	79	24
Total production[2] *(Mboe/d)*	**351**	**304**	425	327	451	350
Proved oil and NGL reserves[3, 4] *(millions of barrels - MMbbls)*	**950**	**841**	866	733	801	674
Proved natural gas reserves *(trillions of cubic feet - Tcf)*[4]	**1.9**	**1.5**	2.2	1.7	2.5	2.0

1 Includes production of synthetic crude oil from Syncrude mining operation.
2 Natural gas is converted to oil equivalent using six Mcf of gas to one boe.
3 Includes reserves of synthetic crude oil from Syncrude mining operation.
4 The Company closed the sale of its Syrian producing assets on January 31, 2006.

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, NGL, BITUMEN, SYNTHETIC CRUDE OIL AND NATURAL GAS BEFORE ROYALTIES BY QUARTER

	2006				2005			
	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	**79.4**	**64.1**	**62.3**	**84.7**	77.9	77.8	64.7	81.1
Oil Sands[1]	**45.4**	**45.6**	**59.0**	**58.2**	38.3	48.9	52.1	48.3
North American Natural Gas	**14.7**	**14.2**	**14.2**	**13.8**	16.2	14.5	14.0	14.0
Northwest Europe	**34.8**	**31.3**	**26.5**	**40.7**	34.3	26.3	38.7	35.6
North Africa/Near East	**50.7**	**49.8**	**49.7**	**47.6**	48.1	49.7	50.4	50.9
Total crude oil and equivalents	**225.0**	**205.0**	**211.7**	**245.0**	214.8	217.2	219.9	229.9
Natural gas *(MMcf/d)*								
North American Natural Gas	**635**	**605**	**611**	**615**	702	654	666	649
Northwest Europe	**78**	**65**	**50**	**59**	78	61	58	65
Northern Latin America	**66**	**56**	**64**	**65**	75	74	72	65
Total natural gas	**779**	**726**	**725**	**739**	855	789	796	779
Total production from continuing operations[2] *(Mboe/d)*	**355**	**326**	**333**	**368**	357	349	353	360
Discontinued operations								
Crude oil and NGL *(Mbbl/d)*	**20.6**	**-**	**-**	**-**	68.9	67.1	65.2	62.4
Natural gas *(MMcf/d)*	**8**	**-**	**-**	**-**	28	26	25	24
Total production from discontinued operations[2] *(Mboe/d)*	**22**	**-**	**-**	**-**	74	71	69	66
Total production[2] *(Mboe/d)*	**377**	**326**	**333**	**368**	431	420	422	426

1 Includes production of synthetic crude oil from Syncrude mining operation.
2 Natural gas is converted to oil equivalent using six Mcf 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, NGL, BITUMEN, SYNTHETIC CRUDE OIL AND NATURAL GAS AFTER ROYALTIES BY QUARTER

	2006 Three Months Ended				2005 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	**71.1**	**59.8**	**60.4**	**82.2**	74.5	73.6	60.4	70.4
Oil Sands[1]	**42.8**	**42.3**	**54.1**	**56.2**	37.9	48.4	51.6	47.8
North American Natural Gas	**11.3**	**10.7**	**11.0**	**10.3**	11.9	10.9	10.6	10.8
Northwest Europe	**34.8**	**31.3**	**26.5**	**40.7**	34.3	26.3	38.7	35.6
North Africa/Near East	**45.7**	**45.2**	**44.9**	**43.0**	44.6	41.7	45.0	46.8
Total crude oil and equivalents	**205.7**	**189.3**	**196.9**	**232.4**	203.2	200.9	206.3	211.4
Natural gas *(MMcf/d)*								
North American Natural Gas	**487**	**491**	**509**	**481**	534	503	527	488
Northwest Europe	**78**	**65**	**50**	**59**	78	61	58	65
Northern Latin America	**32**	**28**	**34**	**32**	38	27	27	25
Total natural gas	**597**	**584**	**593**	**572**	650	591	612	578
Total production from continuing operations[2] *(Mboe/d)*	**305**	**287**	**296**	**328**	312	299	308	308
Discontinued operations								
Crude oil and NGL *(Mbbl/d)*	**5.4**	**-**	**-**	**-**	22.6	20.0	19.3	19.4
Natural gas *(MMcf/d)*	**1**	**-**	**-**	**-**	5	4	4	4
Total production from discontinued operations[2] *(Mboe/d)*	**6**	**-**	**-**	**-**	23	21	20	20
Total production[2] *(Mboe/d)*	**311**	**287**	**296**	**328**	335	320	328	328

1 Includes production of synthetic crude oil from Syncrude mining operation.
2 Natural gas is converted to oil equivalent using six Mcf of gas to one boe.

Production Outlook

Upstream production is expected to increase in 2007 with additional volumes from Buzzard, Terra Nova, the Syncrude expansion, De Ruyter and L5b-C. Offsetting these increases are lower production from North American Natural Gas and natural declines in the North Sea. Production is expected to average in the range of 390,000 boe/d net to 420,000 boe/d net in 2007, up from 2006.

Factors that may impact production during 2007 include reservoir performance, drilling results, facility reliability (particularly at Terra Nova), ramp up of production at Buzzard, De Ruyter and L5b-C, regulatory approval of increased facility throughput at White Rose and the successful execution of planned turnarounds.

The following table shows Petro-Canada's 2007 production outlook for conventional crude oil, NGL, bitumen, synthetic crude oil and natural gas in crude oil equivalents before deduction of royalties.

CONSOLIDATED PRODUCTION FROM CONTINUING OPERATIONS NET
(Mboe/d)

	2006 Actual	2007 Outlook (+/-)
North American Natural Gas		
- Natural gas	**103**	97
- Liquids	**14**	13
East Coast Oil	**73**	87
Oil Sands		
- Syncrude	**31**	34
- MacKay River	**21**	24
International		
- North Africa/Near East[1]	**49**	49
- Northwest Europe	**44**	85
- Northern Latin America	**10**	11
Total from continuing operations	**345**	390 - 420

1 North Africa/Near East excludes production from the mature Syrian producing assets sold in 2006.

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, NGL,
BITUMEN, SYNTHETIC CRUDE OIL AND NATURAL GAS

	Years Ended December 31,		
Average annual price received	**2006**	2005	2004
Crude oil and equivalents *($/bbl)*			
East Coast Oil	**$ 71.12**	$ 63.15	$ 48.39
Oil Sands	**54.60**	46.90	39.90
North American Natural Gas	**64.87**	59.47	47.02
Northwest Europe	**72.67**	66.13	50.37
North Africa/Near East[1]	**72.70**	65.79	48.28
Total crude oil and equivalents from continuing operations	**67.38**	60.45	46.94
Discontinued operations	**71.84**	61.82	46.70
Total crude oil and equivalents	**$ 67.48**	$ 60.77	$ 46.88
North America *($/bbl)*			
Average crude oil and NGL sale price	**$ 70.10**	$ 62.55	$ 48.17
Average bitumen sale price	**28.93**	18.53	18.37
Average synthetic crude oil sale price	**72.13**	70.41	52.40
North America average crude oil and NGL, bitumen and synthetic crude oil price	**$ 64.28**	$ 57.18	$ 45.47
International *($/bbl)*			
Northwest Europe - average crude oil and NGL sale price	**$ 72.67**	$ 66.13	$ 50.37
North Africa/Near East - average crude oil and NGL sale price[1]	**72.70**	65.79	48.28
International - average crude oil and NGL sale price from continuing operations	**$ 72.69**	$ 65.93	$ 49.22
Natural gas *($/Mcf)*			
North American Natural Gas	**$ 6.85**	$ 8.47	$ 6.72
Northwest Europe	**8.91**	7.35	5.65
Northern Latin America	**5.13**	6.62	4.81
Total natural gas from continuing operations	**6.96**	8.30	6.53
Discontinued operations	**7.94**	6.43	4.81
Total natural gas	**$ 6.96**	$ 8.24	$ 6.49

1 North Africa/Near East excludes prices realized on production related to the mature Syrian producing assets sold in January 2006, which are shown as discontinued operations.

The following tables on pages 37 to 40 show Petro-Canada's average product prices, netbacks, net earnings 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 equivalents) for the years indicated. Footnotes for the following tables on pages 37 to 40 can be found on page 40.

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 and NGL production represent about 76% of total Northwest Europe production on an oil-equivalent basis.

NORTH AMERICAN NATURAL GAS

($/Mcfe, unless otherwise indicated)

	2006 Three Months Ended				**Total**	2005 Three Months Ended				Total	Total
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	**2006**	Mar. 31	June 30	Sept. 30	Dec. 31	2005	2004[1]
Average price received	**$ 8.93**	**$ 6.87**	**$ 6.63**	**$ 6.89**	**$ 7.34**	$ 6.95	$ 7.56	$ 8.56	$ 11.72	$ 8.67	$ 6.89
Royalties	**(2.08)**	**(1.37)**	**(1.19)**	**(1.55)**	**(1.55)**	(1.68)	(1.75)	(1.83)	(2.89)	(2.03)	(1.65)
Operating expenses	**(0.97)**	**(1.15)**	**(1.21)**	**(1.23)**	**(1.14)**	(0.77)	(0.91)	(0.98)	(1.14)	(0.95)	(0.76)
Netback	**5.88**	**4.35**	**4.23**	**4.11**	**4.65**	4.50	4.90	5.75	7.69	5.69	4.48
Overhead expenses (G&A)[2]	**(0.24)**	**(0.28)**	**(0.23)**	**(0.25)**	**(0.25)**	(0.16)	(0.23)	(0.21)	(0.19)	(0.20)	(0.19)
Netback after overhead expenses	**5.64**	**4.07**	**4.00**	**3.86**	**4.40**	4.34	4.67	5.54	7.50	5.49	4.29
Processing and other income	**0.03**	**0.09**	**0.06**	**0.06**	**0.06**	0.08	(0.01)	0.01	0.18	0.07	0.06
Exploration expenses	**(0.52)**	**(0.28)**	**(0.22)**	**(0.46)**	**(0.37)**	(0.55)	(0.24)	(0.46)	(0.28)	(0.39)	(0.30)
Depletion, depreciation and amortization	**(1.50)**	**(1.56)**	**(1.56)**	**(1.58)**	**(1.55)**	(1.29)	(1.32)	(1.30)	(1.31)	(1.30)	(1.10)
Income and other taxes	**(1.26)**	**(0.66)**	**(0.73)**	**(0.65)**	**(0.83)**	(0.90)	(1.44)	(1.52)	(1.92)	(1.44)	(1.10)
Net earnings	**$ 2.39**	**$ 1.66**	**$ 1.55**	**$ 1.23**	**$ 1.71**	$ 1.68	$ 1.66	$ 2.27	$ 4.17	$ 2.43	$ 1.85
Production, net *(billion cubic feet equivalent - Bcfe)*	**65.0**	**62.8**	**64.0**	**64.1**	**255.9**	71.9	67.4	69.0	67.4	275.7	288.0

EAST COAST OIL

($/bbl, unless otherwise indicated)

	2006 Three Months Ended				**Total**	2005 Three Months Ended				Total	Total
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	**2006**	Mar. 31	June 30	Sept. 30	Dec. 31	2005	2004
Average price received	**$ 69.21**	**$ 75.85**	**$ 74.26**	**$ 66.32**	**$ 71.12**	$ 55.08	$ 61.41	$ 73.37	$ 64.23	$ 63.15	$ 48.39
Royalties	**(7.15)**	**(6.79)**	**(2.42)**	**(2.02)**	**(4.54)**	(2.35)	(3.33)	(4.76)	(8.44)	(4.78)	(1.89)
Operating expenses	**(5.07)**	**(7.49)**	**(13.79)**	**(4.32)**	**(7.27)**	(3.11)	(3.85)	(5.42)	(5.21)	(4.37)	(2.72)
Netback	**56.99**	**61.57**	**58.05**	**59.98**	**59.31**	49.62	54.23	63.19	50.58	54.00	43.78
Overhead expenses (G&A)[2]	**(0.26)**	**(0.91)**	**(0.42)**	**(0.27)**	**(0.44)**	(0.09)	0.09	-	(0.54)	(0.15)	(0.17)
Netback after overhead expenses	**56.73**	**60.66**	**57.63**	**59.71**	**58.87**	49.53	54.32	63.19	50.04	53.85	43.61
Processing and other income	**(0.02)**	**(0.37)**	**3.83**	**1.70**	**1.20**	0.01	-	0.46	-	0.10	1.66
Depletion, depreciation and amortization	**(8.82)**	**(8.20)**	**(8.28)**	**(9.68)**	**(8.82)**	(9.65)	(10.06)	(9.97)	(9.06)	(9.66)	(9.05)
Income and other taxes	**(16.49)**	**(11.13)**	**(18.13)**	**(17.19)**	**(15.87)**	(11.63)	(15.34)	(17.43)	(14.65)	(14.66)	(11.58)
Net earnings	**$ 31.40**	**$ 41.70**	**$ 35.05**	**$ 34.54**	**$ 35.38**	$ 28.26	$ 28.92	$ 36.25	$ 26.33	$ 29.63	$ 24.64
Production, net *(MMbbls)*	**7.2**	**5.8**	**5.7**	**7.8**	**26.5**	7.0	7.1	6.0	7.5	27.6	28.6

SYNCRUDE

($/bbl, unless otherwise indicated)

	2006 Three Months Ended				Total	2005 Three Months Ended				Total	Total
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	**2006**	Mar. 31	June 30	Sept. 30	Dec. 31	2005	2004
Average price received	**$ 69.29**	**$ 78.38**	**$ 77.91**	**$ 63.68**	**$ 72.13**	$ 64.40	$ 67.08	$ 77.16	$ 70.82	$ 70.41	$ 52.40
Royalties	**(6.72)**	**(8.45)**	**(8.48)**	**(4.59)**	**(6.98)**	(0.65)	(0.66)	(0.78)	(0.71)	(0.71)	(0.61)
Operating expenses	**(43.87)**	**(32.77)**	**(21.85)**	**(26.26)**	**(30.00)**	(44.24)	(26.70)	(26.95)	(34.04)	(31.90)	(21.13)
Netback	**18.70**	**37.16**	**47.58**	**32.83**	**35.15**	19.51	39.72	49.43	36.07	37.80	30.66
Processing and other income	**-**	**-**	**5.96**	**-**	**1.65**	-	-	-	-	-	-
Depletion, depreciation and amortization	**(2.70)**	**(2.77)**	**(3.79)**	**(5.15)**	**(3.74)**	(1.89)	(1.89)	(1.96)	(2.04)	(1.95)	(1.79)
Income and other taxes	**(5.38)**	**3.00**	**(16.81)**	**(9.32)**	**(7.75)**	(5.18)	(13.64)	(15.47)	(11.45)	(12.03)	(9.31)
Net earnings	**$ 10.62**	**$ 37.39**	**$ 32.94**	**$ 18.36**	**$ 25.31**	$ 12.44	$ 24.19	$ 32.00	$ 22.58	$ 23.82	$ 19.56
Production, net *(MMbbls)*	**2.2**	**2.6**	**3.1**	**3.4**	**11.3**	1.7	2.5	2.6	2.5	9.3	10.5

MACKAY RIVER

($/bbl, unless otherwise indicated)

	2006 Three Months Ended				Total	2005 Three Months Ended				Total	Total
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	**2006**	Mar. 31	June 30	Sept. 30	Dec. 31	2005	2004
Average price received	**$ 11.24**	**$ 39.37**	**$ 39.13**	**$ 25.84**	**$ 28.93**	$ 10.88	$ 13.92	$ 31.98	$ 15.27	$ 18.61	$ 18.37
Royalties	**(0.09)**	**(0.36)**	**(2.07)**	**0.85**	**(0.49)**	(0.08)	(0.11)	(0.30)	(0.12)	(0.16)	(0.16)
Operating expenses	**(18.60)**	**(21.24)**	**(14.01)**	**(15.42)**	**(16.93)**	(14.80)	(15.65)	(14.08)	(20.72)	(16.29)	(20.98)
Netback	**(7.45)**	**17.77**	**23.05**	**11.27**	**11.51**	(4.00)	(1.84)	17.60	(5.57)	2.16	(2.77)
Overhead expenses (G&A)[2]	**(0.92)**	**(0.94)**	**(0.76)**	**(1.01)**	**(0.90)**	(0.74)	(0.80)	(0.69)	(0.84)	(0.77)	(0.89)
Netback after overhead expenses	**(8.37)**	**16.83**	**22.29**	**10.26**	**10.61**	(4.74)	(2.64)	16.91	(6.41)	1.39	(3.66)
Processing and other income	**0.02**	**(0.31)**	**(0.03)**	**(0.07)**	**(0.05)**	(0.51)	0.16	0.02	-	(0.06)	-
Exploration expenses	**0.02**	**-**	**0.01**	**(0.18)**	**(0.04)**	(0.44)	(0.04)	0.03	(0.07)	(0.12)	(0.03)
Depletion, depreciation and amortization	**(4.16)**	**(3.16)**	**(5.22)**	**(5.51)**	**(4.63)**	(3.18)	(3.18)	(3.08)	(3.53)	(3.24)	(3.16)
Income and other taxes	**3.87**	**(0.87)**	**(6.02)**	**(1.55)**	**(1.43)**	2.63	1.22	(4.37)	2.70	0.35	1.94
Net earnings (loss)	**$ (8.62)**	**$ 12.49**	**$ 11.03**	**$ 2.95**	**$ 4.46**	$ (6.24)	$ (4.48)	$ 9.51	$ (7.31)	$ (1.68)	$ (4.91)
Production, net *(MMbbls)*	**1.9**	**1.5**	**2.3**	**2.0**	**7.7**	1.7	1.9	2.2	2.0	7.8	6.1

NORTHWEST EUROPE[3, 4]

($/boe, unless otherwise indicated)

	2006 Three Months Ended				Total	2005 Three Months Ended				Total	Total
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	**2006**	Mar. 31	June 30	Sept. 30	Dec. 31	2005	2004
Average price received[5]	**$ 68.57**	**$ 69.27**	**$ 69.95**	**$ 65.31**	**$ 68.07**	$ 53.61	$ 59.11	$ 65.82	$ 63.82	$ 60.74	$ 46.08
Royalties	**(1.33)**	**(0.79)**	**(0.97)**	**(0.55)**	**(0.91)**	-	(2.06)	(0.96)	(0.62)	(0.85)	-
Net revenue	**67.24**	**68.48**	**68.98**	**64.76**	**67.16**	53.61	57.05	64.86	63.20	59.89	46.08
Operating expenses	**(8.02)**	**(9.46)**	**(11.29)**	**(9.87)**	**(9.56)**	(8.23)	(10.66)	(8.86)	(10.99)	(9.62)	(7.89)
Netback	**59.22**	**59.02**	**57.69**	**54.89**	**57.60**	45.38	46.39	56.00	52.21	50.27	38.19
Overhead expenses (G&A)[2]	**(2.34)**	**(2.19)**	**(3.44)**	**0.99**	**(1.55)**	(1.54)	(2.98)	(2.48)	(1.96)	(2.20)	(0.96)
Netback after overhead expenses	**56.88**	**56.83**	**54.25**	**55.88**	**56.05**	43.84	43.41	53.52	50.25	48.07	37.23
Processing and other income	**2.07**	**(1.14)**	**(0.01)**	**1.44**	**0.70**	2.62	0.65	(3.26)	1.50	1.81	(0.07)
Exploration expenses	**(0.75)**	**(4.61)**	**2.02**	**(1.44)**	**(1.33)**	(0.75)	(2.06)	(1.15)	(1.93)	(1.43)	(2.25)
Depletion, depreciation and amortization	**(15.64)**	**(16.20)**	**(17.13)**	**(23.04)**	**(18.22)**	(14.31)	(15.06)	(15.19)	(14.64)	(14.79)	(13.48)
Income and other taxes[6]	**(75.56)**	**(17.59)**	**(19.37)**	**(21.30)**	**(34.68)**	(14.17)	(11.71)	(14.62)	(14.60)	(14.50)	(8.32)
Net earnings	**$ (33.00)**	**$ 17.29**	**$ 19.76**	**$ 11.54**	**$ 2.52**	$ 17.23	$ 15.23	$ 19.30	$ 20.58	$ 19.16	$ 13.11
Production, net *(MMboe)*	**4.3**	**3.8**	**3.2**	**4.6**	**15.9**	4.3	3.3	4.4	4.3	16.3	20.0

NORTH AFRICA/NEAR EAST[3, 7, 8]

($/boe, unless otherwise indicated)

	2006 Three Months Ended				Total	2005 Three Months Ended				Total	Total
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	**2006**	Mar. 31	June 30	Sept. 30	Dec. 31	2005	2004
Average price received[5]	**$ 71.29**	**$ 77.27**	**$ 74.92**	**$ 67.15**	**$ 72.70**	$ 56.01	$ 69.84	$ 74.20	$ 62.44	$ 65.75	$ 48.35
Royalties	**(7.08)**	**(7.15)**	**(7.25)**	**(6.66)**	**(7.01)**	(4.04)	(11.17)	(8.08)	(6.91)	(7.59)	(7.08)
Net revenue	**64.21**	**70.12**	**67.67**	**60.49**	**65.69**	51.97	58.67	66.12	55.53	58.16	41.27
Operating expenses	**(5.40)**	**(3.49)**	**(4.73)**	**(6.06)**	**(4.91)**	(5.34)	(3.35)	(5.97)	(3.39)	(4.50)	(5.56)
Netback	**58.81**	**66.63**	**62.94**	**54.43**	**60.78**	46.63	55.32	60.15	52.14	53.66	35.71
Overhead expenses (G&A)[2]	**(0.61)**	**(0.63)**	**(0.62)**	**(1.38)**	**(0.80)**	(1.17)	(0.34)	(0.66)	(0.82)	(0.75)	(1.03)
Netback after overhead	**58.20**	**66.00**	**62.32**	**53.05**	**59.98**	45.46	54.98	59.49	51.32	52.91	34.68
Processing and other income	**(0.15)**	**(0.54)**	**0.40**	**(0.91)**	**(0.30)**	2.19	3.08	1.33	3.26	2.47	(0.34)
Exploration expenses	**(0.68)**	**(0.48)**	**(0.33)**	**(0.38)**	**(0.47)**	(0.13)	(1.42)	(0.16)	(0.41)	(0.53)	(0.89)
Depletion, depreciation and amortization	**(1.49)**	**(1.52)**	**(1.54)**	**(1.49)**	**(1.51)**	(2.33)	(2.27)	(2.14)	(1.46)	(2.04)	(2.73)
Income and other taxes	**(52.74)**	**(59.97)**	**(54.16)**	**(48.53)**	**(53.89)**	(39.88)	(47.19)	(52.58)	(46.26)	(46.58)	(26.58)
Net earnings	**$ 3.14**	**$ 3.49**	**$ 6.69**	**$ 1.74**	**$ 3.81**	$ 5.31	$ 7.18	$ 5.94	$ 6.45	$ 6.23	$ 4.14
Production, net *(MMboe)*	**4.6**	**4.5**	**4.6**	**4.4**	**18.1**	4.4	4.5	4.6	4.7	18.2	18.5

NORTHERN LATIN AMERICA[3, 9]

($/Mcf, unless otherwise indicated)

	2006 Three Months Ended				Total	2005 Three Months Ended				Total	Total
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	**2006**	Mar. 31	June 30	Sept. 30	Dec. 31	2005	2004
Average price received	**$ 6.32**	**$ 5.08**	**$ 4.46**	**$ 4.70**	**$ 5.13**	$ 5.09	$ 5.05	$ 6.90	$ 9.82	$ 6.62	$ 4.81
Royalties	**-**	**(0.49)**	**(0.15)**	**(2.51)**	**(1.26)**	-	(4.42)	(4.86)	(1.83)	(2.06)	(1.05)
Net revenue	**6.32**	**4.59**	**4.31**	**2.19**	**3.87**	5.09	0.63	2.04	7.99	4.56	3.76
Operating expenses	**(0.20)**	**(0.16)**	**(0.07)**	**(0.28)**	**(0.18)**	(0.22)	(0.14)	(0.18)	(0.15)	(0.17)	(0.12)
Netback	**6.12**	**4.43**	**4.24**	**1.91**	**3.69**	4.87	0.49	1.86	7.84	4.39	3.64
Overhead expenses (G&A)[2]	**(0.07)**	**(0.19)**	**(0.12)**	**(0.21)**	**(0.15)**	(0.11)	(0.08)	(0.08)	(0.13)	(0.10)	(0.13)
Netback after overhead expenses	**6.05**	**4.24**	**4.12**	**1.70**	**3.54**	4.76	0.41	1.78	7.71	4.29	3.51
Processing and other income	**-**	**(0.15)**	**0.10**	**(0.07)**	**(0.03)**	0.02	0.08	(0.02)	-	0.02	(0.04)
Exploration expenses	**(0.01)**	**-**	**-**	**(0.01)**	**(0.01)**	-	-	-	-	-	-
Depletion, depreciation and amortization	**(0.73)**	**(0.73)**	**(0.73)**	**(0.73)**	**(0.73)**	(0.65)	(0.65)	(0.65)	(0.65)	(0.65)	(0.57)
Income and other taxes	**(3.20)**	**(2.07)**	**(1.97)**	**0.13**	**(1.29)**	(2.48)	1.19	0.54	(4.22)	(1.89)	(1.62)
Net earnings	**$ 2.11**	**$ 1.29**	**$ 1.52**	**$ 1.02**	**$ 1.48**	$ 1.65	$ 1.03	$ 1.65	$ 2.84	$ 1.77	$ 1.28
Production, net *(Bcf)*	**5.9**	**5.1**	**5.9**	**6.0**	**22.9**	6.8	6.8	6.6	6.1	26.3	26.1

DISCONTINUED OPERATIONS[8]

($/boe, unless otherwise indicated)

	2006 Three Months Ended				Total	2005 Three Months Ended				Total	Total
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	**2006**	Mar. 31	June 30	Sept. 30	Dec. 31	2005	2004
Average price received[5]	**$ 70.36**	**-**	**-**	**-**	**$ 70.36**	$ 52.83	$ 58.96	$ 65.24	$ 62.80	$ 60.39	$ 45.91
Royalties	**(52.10)**	**-**	**-**	**-**	**(52.10)**	(35.71)	(41.73)	(45.73)	(43.60)	(42.15)	(31.49)
Net revenue	**18.26**	**-**	**-**	**-**	**18.26**	17.12	17.23	19.51	19.20	18.24	14.42
Operating expenses	**(2.65)**	**-**	**-**	**-**	**(2.65)**	(3.91)	(3.08)	(4.52)	(3.96)	(3.87)	(3.94)
Netback	**15.61**	**-**	**-**	**-**	**15.61**	13.21	14.15	14.99	15.24	14.37	10.48
Overhead expenses (G&A)[2]	**(0.23)**	**-**	**-**	**-**	**(0.23)**	(0.21)	(0.17)	(0.12)	(0.23)	(0.19)	(0.14)
Netback after overhead	**15.38**	**-**	**-**	**-**	**15.38**	13.00	13.98	14.87	15.01	14.18	10.34
Processing and other income	**(1.06)**	**-**	**-**	**-**	**(1.06)**	0.33	0.47	(0.22)	(0.07)	0.14	(0.04)
Depletion, depreciation and amortization	**-**	**-**	**-**	**-**	**-**	(6.89)	(6.63)	(6.30)	(2.66)	(5.67)	(5.02)
Income and other taxes	**(5.11)**	**-**	**-**	**-**	**(5.11)**	(3.88)	(4.39)	(5.10)	(4.87)	(4.55)	(3.34)
Net earnings	**$ 9.21**	**-**	**-**	**-**	**$ 9.21**	$ 2.56	$ 3.43	$ 3.25	$ 7.41	$ 4.10	$ 1.94
Production, net *(MMboe)*	**2.0**	**-**	**-**	**-**	**2.0**	6.6	6.5	6.4	6.1	25.6	29.0

1 North American Natural Gas includes U.S. Rockies post-acquisition date as 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 equivalents. Northern Latin America includes only natural gas.
4 Production in Northwest Europe is subject to a conventional royalty and tax regime. No royalty is payable on production in the U.K. sector. Royalty is payable on onshore production 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 equivalents.
6 In 2006, the Company recorded a $242 million charge for the U.K. supplemental corporate tax rate adjustment.
7 Excludes assets located in Kazakhstan, which were sold in 2004.
8 North Africa/Near East excludes production related to the mature Syrian producing assets sold in 2006, which are shown as discontinued operations.
9 Natural gas production in Trinidad and Tobago is held pursuant to a PSC with the government of that country. The government share is split between royalty and tax for Canadian reporting purposes.

Reserves

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). This 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 oil and gas reserves. In addition, the reserves for the Syncrude mining operation were prepared in accordance with SEC Industry Guide 7.

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 valid 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. The Company believes these reserves policies, procedures and practices conform to the requirements of applicable Canadian and U.S. SEC regulations, and of the Association of Professional Engineers, Geologists and Geophysicists of Alberta's 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 and auditors. For 2006, 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 29% of the Company's proved crude oil, natural gas and NGL reserves outside of North America. Similarly, Sproule audited 53% of Petro-Canada's North American proved oil and gas reserves. If the Syncrude oil sands mining proved reserves are included, the percentage of total North American reserves audited was 34%. The independent auditors' and evaluators' reports concluded that the Company's year-end 2006 proved reserves estimates are reasonable.

Sproule and GCA also audited Petro-Canada's reserves policies, procedures and practices. They concluded that Petro-Canada's reserves 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, has tested aspects of 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 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 reserves evaluation. The supervisors, as responsible qualified reserves evaluators, sign the annual reserves evaluations for their respective areas.

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

Major Property Reviews: Each year, prior to business plan development, a series of reviews are 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 reserves 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. Each year's annual independent evaluator assessment plan is reviewed and approved by the Audit, Finance and Risk Committee of the Board. 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 management in each business unit reviews the reserves data prepared by the reservoir engineering staff. The officer responsible for each business unit signs an assertion regarding the quality of the reserves estimates and the processes applied. Also in December, Petro-Canada's year-end reserves and preliminary reports from the independent evaluators are reviewed by the Reserves Steering Committee and 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.

The following tables show the Company's estimates of Petro-Canada's total proved crude oil, natural gas, bitumen and synthetic crude oil reserves as at December 31, 2006, and average 2006 daily production by major fields.

MAJOR RESERVES AND PRODUCTION LOCATIONS, BEFORE DEDUCTION OF ROYALTIES

Crude Oilfield/Facility[1]	Location	**Proved Reserves[2, 3] at December 31, 2006** *(MMbbls)*	**Average 2006 Daily Production** *(Mbbl/d)*
Syncrude[3]	Alberta	**344**	**31**
MacKay River	Alberta	**157**	**22**
Buzzard	Offshore U.K.	**104**	**-**
Hibernia	Offshore Newfoundland and Labrador	**54**	**36**
Amal	Libya	**42**	**16**
Terra Nova	Offshore Newfoundland and Labrador	**38**	**13**
White Rose	Offshore Newfoundland and Labrador	**32**	**24**
Ghani/Zenad Farrud	Libya	**30**	**11**
Ghani Gir/Facha	Libya	**20**	**7**
Ferrier	Alberta	**16**	**2**
Other		**92**	**51**
Total		**929**	**213**

Natural Gas Field/Facility[1]	Location	**Proved Reserves at December 31, 2006** *(Bcf)*	**Average 2006 Daily Production[2]** *(MMcf/d)*
Wildcat Hills area	Alberta	**326**	**114**
Hanlan area	Alberta	**224**	**94**
NCMA-1	Offshore Trinidad and Tobago	**215**	**63**
Medicine Hat	Alberta	**185**	**45**
Jedney/Bubbles area	British Columbia	**117**	**28**
Alderson	Alberta	**97**	**25**
Laprise area	British Columbia	**83**	**27**
Denver-Julesburg area	U.S.	**78**	**20**
Ricinus/Bearberry/Strachan	Alberta	**71**	**45**
Powder River area	U.S.	**59**	**20**
Other		**490**	**260**
Total		**1,945**	**741**

1 Fields are onshore unless otherwise indicated.
2 The reserves and production figures shown in this table do not include NGL. Total Company proved reserves (include oil sands mining) of crude oil and NGL at year-end 2006 were 950 MMbbls.
3 Syncrude reserves are synthetic crude oil reserves from oil sands mining. See Legal Notice on page 1 regarding oil sands mining.

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. 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 table shows, for the years indicated, Petro-Canada's estimates of proved reserves, before royalties: TABLE 1 - Oil and Gas Activities; TABLE 2 - Oil Sands Mining; TABLE 3 - Total of Oil and Gas Activities and Oil Sands Mining.

PROVED RESERVES BEFORE ROYALTIES

(Crude oil and equivalents in MMbbls; Natural gas in Bcf)

	TABLE 1 Oil and Gas Activities[1, 2, 3, 4, 5]																	**TABLE 2 Oil Sands Mining** [1, 2, 3, 4, 5]	**TABLE 3 Total Oil and Gas Activities and Oil Sands Mining**
	International							**North America**											
								North American Natural Gas											
	Northwest Europe[6]		North Africa/Near East [7, 8, 9, 10, 11, 16]		Northern Latin America [7, 12]	Subtotal		Western Canada		U.S. Rockies		East Coast	Oil Sands	Subtotal		**Total**		**Syncrude Mining Operation** [13]	**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	Natural gas	Crude oil & NGL	Bitumen	Crude oil, NGL & bitumen	Natural gas	**Crude oil, NGL & bitumen**	**Natural gas**	**Synthetic crude oil**[17]	**Crude oil & equivalents**
Beginning of year 2005	**148**	**131**	**210**	**39**	**265**	**358**	**435**	**38**	**1,950**	**6**	**88**	**68**	**-**	112	**2,038**	**470**	**2,473**	**331**	**801**
Revisions of previous estimates[14]	2	4	29	(14)	-	31	(10)	5	(36)	2	22	68	8	83	(14)	114	(24)	20	134
Sale of reserves in place	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Purchase of reserves in place	5	4	-	-	-	5	4	-	-	-	-	-	-	-	-	5	4	-	5
Discoveries, extension and improved recovery	-	-	3	-	-	3	-	4	44	-	-	23	-	27	44	30	44	-	30
Production net	(12)	(24)	(42)	(9)	(26)	(54)	(59)	(5)	(229)	(1)	(14)	(27)	(8)	(41)	(243)	(95)	(302)	(9)	(104)
End of year 2005	**143**	**115**	**200**	**16**	**239**	**343**	**370**	**42**	**1,729**	**7**	**96**	**132**	**-**	**181**	**1,825**	**524**	**2,195**	**342**	**866**
Revisions of previous estimates[14]	13	(6)	(2)	-	(1)	11	(7)	1	(47)	2	64	18	165	186	17	197	10	14	211
Sale of reserves in place	-	(2)	(46)	(15)	-	(46)	(17)	-	(1)	-	-	-	-	-	(1)	(46)	(18)	-	(46)
Purchase of reserves in place	-	-	-	-	-	-	-	-	1	-	-	-	-	-	1	-	1	-	-
Discoveries, extensions and improved recovery	-	-	-	-	-	-	-	-	27	-	-	-	-	-	27	-	27	-	-
Production net	(12)	(23)	(18)	-	(23)	(30)	(46)	(4)	(209)	(1)	(15)	(27)	(8)	(40)	(224)	(70)	(270)	(11)	(81)
End of year 2006	**144**	**84**	**134**	**1**	**215**	**278**	**300**	**39**	**1,500**	**8**	**145**	**123**	**157**	**327**	**1,645**	**605**	**1,945**	**345**	**950**
Proved undeveloped reserves[15]																			
Beginning of year 2005	**101**	**14**	**21**	**-**	**178**	**122**	**192**	**1**	**82**	**2**	**24**	**19**	**-**	**22**	**106**	**144**	**298**	**189**	**333**
End of year 2005	**95**	**14**	**22**	**-**	**178**	**117**	**192**	**1**	**132**	**3**	**30**	**43**	**-**	**47**	**162**	**164**	**354**	**209**	**373**
End of year 2006	**42**	**3**	**3**	**-**	**138**	**45**	**141**	**-**	**56**	**4**	**36**	**33**	**129**	**166**	**92**	**211**	**233**	**219**	**430**

The following table shows, for the years indicated, Petro-Canada's estimates of proved reserves, after royalties: TABLE 1 - Oil and Gas Activities; TABLE 2 - Oil Sands Mining; TABLE 3 - Total of Oil and Gas Activities and Oil Sands Mining.

PROVED RESERVES AFTER ROYALTIES

(Crude oil and equivalents in MMbbls; Natural gas in Bcf)

	TABLE 1 Oil and Gas Activities[1, 2, 3, 4, 5]																	TABLE 2 Oil Sands Mining[1, 2, 3, 4, 5]	TABLE 3 Total Oil and Gas Activities and Oil Sands Mining
	International							**North America**											
								North American Natural Gas											
	Northwest Europe[6]		North Africa/Near East[7, 8, 9, 10, 11, 16]		Northern Latin America[7, 12]	Subtotal		Western Canada		U.S. Rockies		East Coast	Oil Sands	Subtotal		**Total**		**Syncrude Mining Operation**[13]	**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	Natural gas	Crude oil & NGL	Bitumen	Crude oil, NGL & bitumen	Natural gas	**Crude oil, NGL & bitumen**	**Natural gas**	**Synthetic crude oil**[17]	**Crude oil & equivalents**
Beginning of year 2005	**148**	**131**	**144**	**13**	**225**	**292**	**369**	**30**	**1,508**	**4**	**73**	**61**	**-**	**95**	**1,581**	**387**	**1,950**	**287**	**674**
Revisions of previous estimates[14]	1	5	28	(6)	(1)	29	(2)	5	(28)	7	18	57	8	77	(10)	106	(12)	9	115
Sale of reserves in place	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Purchase of reserves in place	5	3	-	-	-	5	3	-	-	-	-	-	-	-	-	5	3	-	5
Discoveries, extensions and improved recovery	-	-	2	-	-	2	-	3	34	-	-	20	-	23	34	25	34	-	25
Production net	(12)	(24)	(22)	(2)	(21)	(34)	(47)	(4)	(175)	(6)	(12)	(25)	(8)	(43)	(187)	(77)	(234)	(9)	(86)
End of year 2005	**142**	**115**	**152**	**5**	**203**	**294**	**323**	**34**	**1,339**	**5**	**79**	**113**	**-**	**152**	**1,418**	**446**	**1,741**	**287**	**733**
Revisions of previous estimates[14]	13	(6)	28	10	(2)	41	2	1	(43)	2	55	10	159	172	12	213	14	12	225
Sale of reserves in place	-	(2)	(42)	(15)	-	(42)	(17)	-	(1)	-	-	-	-	-	(1)	(42)	(18)	-	(42)
Purchase of reserves in place	-	-	-	-	-	-	-	-	1	-	-	-	-	-	1	-	1	-	-
Discoveries, extensions and improved recovery	-	-	-	-	-	-	-	-	21	-	-	-	-	-	21	-	21	-	-
Production net	(12)	(23)	(16)	-	(12)	(28)	(35)	(3)	(166)	(1)	(12)	(25)	(8)	(37)	(178)	(65)	(213)	(10)	(75)
End of year 2006	**143**	**84**	**122**	**-**	**189**	**265**	**273**	**32**	**1,151**	**6**	**122**	**98**	**151**	**287**	**1,273**	**552**	**1,546**	**289**	**841**
Proved undeveloped reserves[15]																			
Beginning of year 2005	**101**	**14**	**14**	**-**	**151**	**115**	**165**	**1**	**65**	**2**	**20**	**16**	**-**	**19**	**85**	**134**	**250**	**161**	**295**
End of year 2005	**95**	**14**	**15**	**-**	**151**	**110**	**165**	**1**	**99**	**3**	**25**	**33**	**-**	**37**	**124**	**147**	**289**	**173**	**320**
End of year 2006	**42**	**4**	**2**	**-**	**121**	**44**	**125**	**-**	**42**	**4**	**30**	**24**	**124**	**152**	**72**	**196**	**197**	**182**	**378**

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 U.S. 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, procedures and practices 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 also reflect net overriding 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 which do not transfer title of the product to those companies.

8 In Petro-Canada's PSCs, after royalty proved reserves have been determined using the economic interest method and include the Company's share of future cost recovery and profit oil after foreign governments' royalty interest, and include reserves relating to income tax payable. Under this method, reported reserves will increase as oil prices decrease (and vice versa) since the bbls necessary to achieve cost recovery change with the prevailing oil prices.

9 Reserves in Syria are held under PSCs with the Syrian government and are calculated as per footnote 8.

10 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 PSC with the Libyan government, with reserves being calculated as per footnote 8.

11 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 2006 was 10 MMbbls of crude oil and NGL and zero Bcf of natural gas. At year-end 2005, the volume was 59 MMbbls of crude oil and NGL and 15 Bcf of natural gas. The after royalty reserves volumes were: year-end 2006 - 7 MMbbls of crude oil and NGL and zero Bcf of natural gas, and year-end 2005 - 21 MMbbls of crude oil and NGL and 5 Bcf of natural gas. Reserves information for 2005 includes the Syrian producing assets sold in 2006.

12 Natural gas reserves in Trinidad and Tobago are held under a PSC with the applicable government and are calculated as per footnote 8. The volume of proved natural gas reserves before royalties reported above held under PSCs in Trinidad and Tobago at the end of 2006 was 215 Bcf. At year-end 2005, the volume was 239 Bcf. The after royalty reserves volumes were: year-end 2006 - 189 Bcf, and year-end 2005 - 203 Bcf.

13 U.S. SEC regulations do not define proved reserves of synthetic crude oil from oil sands mining operations as an oil and gas activity. These reserves are classified as a mining activity and are estimated in accordance with SEC Industry Guide 7. 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. Syncrude proved oil sands mining reserves have been determined using SEC year-end prices in the economics.

14 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.

15 Proved undeveloped crude oil and NGL proved reserves in Table 1 represent approximately 35% of Petro-Canada's total 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, MacKay River, White Rose, Terra Nova and Hibernia. 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. Fifty-nine per cent of the proved undeveloped gas reserves are associated with the currently producing NCMA-1 development in Trinidad and Tobago. Generally, the Company plans to develop proved undeveloped natural gas reserves in the next few years.

16 The Company closed the sale of its Syrian producing assets on January 31, 2006.

17 For internal management purposes, we view the oil sands mining reserves as part of the Company's total exploration and production operations.

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, 2006 were used in deriving the Standardized Measure: West Texas Intermediate (WTI) at Cushing $61.05/bbl US, Dated Brent at Sullom Voe $58.93/bbl US, New York Mercantile Exchange (NYMEX) gas price at the Henry Hub $5.84/MMBtu US, and Alberta price of natural gas at the AECO-C Hub Cdn $5.68/gigajoule (GJ). The following currency exchange rates were also used: Cdn$/US$ 1.1654, Cdn$/euro 1.5377, Cdn$/British pound 2.2824.

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

	Western Canada[1]			U.S. Rockies			East Coast Oil[2]		
	2006	2005	2004	**2006**	2005	2004	**2006**	2005	2004
Future cash flows	**$ 12,513**	$ 15,255	$ 11,470	**$ 1,130**	$ 1,058	$ 688	**$ 7,164**	$ 7,746	$ 2,580
Future production, development and asset retirement costs	**(5,593)**	(2,631)	(2,344)	**(525)**	(402)	(281)	**(1,499)**	(1,314)	(786)
Future income taxes	**(1,764)**	(4,121)	(2,900)	**(187)**	(245)	(110)	**(1,553)**	(1,993)	(467)
Future net cash flows	**5,156**	8,503	6,226	**418**	411	297	**4,112**	4,439	1,327
Discount of 10% for estimated timing of cash flows	**(1,927)**	(3,413)	(2,676)	**(154)**	(168)	(118)	**(879)**	(1,164)	(285)
Discounted future net cash flows	**$ 3,229**	$ 5,090	$ 3,550	**$ 264**	$ 243	$ 179	**$ 3,233**	$ 3,275	**$ 1,042**

	Northwest Europe			North Africa/Near East			Northern Latin America		
	2006	2005	2004	**2006**	2005	2004	**2006**	2005	2004
Future cash flows	$ 8,506	$ 9,092	$ 7,624	**$ 8,011**	$ 8,984	$ 6,039	**$ 838**	$ 1,737	$ 1,031
Future production, development and asset retirement costs	**(2,918)**	(2,844)	(3,190)	**(1,024)**	(800)	(981)	**(282)**	(248)	(151)
Future income taxes	**(2,966)**	(3,227)	(1,682)	**(6,088)**	(7,092)	(4,344)	**(289)**	(813)	(479)
Future net cash flows	**2,622**	3,021	2,752	**899**	1,092	714	**267**	676	401
Discount of 10% for estimated timing of cash flows	**(532)**	(859)	(929)	**(309)**	(392)	(271)	**(119)**	(305)	(188)
Discounted future net cash flows	**$ 2,090**	$ 2,162	$ 1,823	**$ 590**	$ 700	$ 443	**$ 148**	$ 371	$ 213

	Continuing Operations			Discontinued Operations			Total		
	2006	2005	2004	**2006**	2005	2004	**2006**	2005	2004
Future cash flows	**$ 38,162**	$ 43,872	$ 29,432	**$ -**	$ 1,008	$ 1,038	**$ 38,162**	$ 44,880	$ 30,470
Future production, development and asset retirement costs	**(11,841)**	(8,239)	(7,733)	**-**	(336)	(453)	**(11,841)**	(8,575)	(8,186)
Future income taxes	**(12,847)**	(17,491)	(9,982)	**-**	(244)	(219)	**(12,847)**	(17,735)	(10,201)
Future net cash flows	**13,474**	18,142	11,717	**-**	428	366	**13,474**	18,570	12,083
Discount of 10% for estimated timing of cash flows	**(3,920)**	(6,301)	(4,467)	**-**	(81)	(84)	**(3,920)**	(6,382)	(4,551)
Discounted future net cash flows	**$ 9,554**	$ 11,841	$ 7,250	**$ -**	$ 347	$ 282	**$ 9,554**	$ 12,188	$ 7,532

1 Western Canada includes the cash flows of MacKay River in 2006. There were no proved reserves at MacKay River at year-end 2004 and 2005.
2 Additional East Coast Oil reserves quantities will be booked as proved reserves as development proceeds.

SUMMARY OF CHANGES IN PRESENT VALUE OF ESTIMATED FUTURE CASH FLOWS

(millions of Canadian dollars)

	2006	2005	2004
Balance at beginning of year	**$ 12,188**	$ 7,532	$ 6,216
Changes result from:			
Sales and transfers of oil and gas produced, net of production costs	**(5,480)**	(5,273)	(4,348)
Net changes in prices, operating costs and royalties	**(2,859)**	9,013	2,482
Extensions, discoveries, additions and improved recoveries	**59**	1,383	395
Changes in estimated future development costs	**(597)**	(758)	(1,235)
Development costs incurred during the year	**900**	900	966
Revisions of previous quantity estimates	**2,081**	3,328	979
Accretion of discount	**2,295**	1,374	1,117
Net change in income tax	**2,572**	(4,711)	(1,186)
Purchase and sale of reserves in place	**(367)**	246	2,017
Changes in timing and other	**(1,238)**	(846)	129
Net change	**(2,634)**	4,656	1,316
Balance at end of year	**$ 9,554**	$ 12,188	$ 7,532

Abandonment 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, 2006, the total of these future costs is estimated to be $3,418 million undiscounted, or $761 million discounted at 10%. The Company's upstream operations expect to spend approximately $36 million, $47 million and $41 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, 2006

	Crude Oil Wells		Natural Gas Wells		Total Wells	
	Gross[2]	**Net[3]**	**Gross[2]**	**Net[3]**	**Gross[2]**	**Net[3]**
North America						
North American Natural Gas - conventional oil and gas	926	744	5,240	3,575	6,166	4,319
East Coast Oil - conventional oil	91	23	-	-	91	23
Oil Sands - *in situ* bitumen recovery	42	42	-	-	42	42
Total North America	1,059	809	5,240	3,575	6,299	4,384
International						
Northwest Europe - conventional oil and gas	42	17	31	4	73	21
North Africa/Near East - conventional oil and gas	237	109	-	-	237	109
Northern Latin America - natural gas	-	-	9	2	9	2
Total International	279	126	40	6	319	132
Total productive wells from continuing operations						
Discontinued operations	-	-	-	-	-	-
Total productive wells	1,338	935	5,280	3,581	6,618	4,516

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, 2006

	Developed Lands[1]				**Undeveloped Lands[1]**				**Total**			
	2006		2005		**2006**		2005		**2006**		2005	
(millions of acres)	**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	**2.2**	**1.1**	2.1	1.2	**2.6**	**2.1**	3.1	2.6	**4.8**	**3.2**	5.2	3.8
Oil Sands	**0.4**	**0.2**	0.4	0.2	**0.4**	**0.3**	0.3	0.2	**0.8**	**0.5**	0.7	0.4
East Coast Oil offshore	**0.1**	**-**	0.1	-	**2.0**	**0.7**	2.4	0.9	**2.1**	**0.7**	2.5	0.9
Other frontier[4]	**-**	**-**	-	-	**8.9**	**7.1**	9.0	7.1	**8.9**	**7.1**	9.0	7.1
Total Canada	**2.7**	**1.3**	2.6	1.4	**13.9**	**10.2**	14.8	10.8	**16.6**	**11.5**	17.4	12.2
United States[5]	**0.1**	**0.1**	0.1	-	**2.8**	**1.2**	2.4	1.4	**2.9**	**1.3**	2.5	1.4
International												
North Africa/Near East	**0.4**	**0.2**	0.4	0.2	**26.9**	**21.4**	25.8	20.0	**27.3**	**21.6**	26.2	20.2
Northwest Europe	**0.1**	**0.1**	0.1	-	**2.4**	**0.8**	2.4	1.0	**2.5**	**0.9**	2.5	1.0
Northern Latin America	**0.1**	**-**	0.1	-	**1.2**	**1.0**	1.2	1.0	**1.3**	**1.0**	1.3	1.0
Total International	**0.6**	**0.3**	0.6	0.2	**30.5**	**23.2**	29.4	22.0	**31.1**	**23.5**	30.0	22.2
Total from continuing operations	**3.4**	**1.7**	3.3	1.6	**47.2**	**34.6**	46.6	34.2	**50.6**	**36.3**	49.9	35.8
Discontinued operations	-	-	0.5	0.2	-	-	-	-	-	-	0.5	0.2
Total	**3.4**	**1.7**	3.8	1.8	**47.2**	**34.6**	46.6	34.2	**50.6**	**36.3**	50.4	36.0

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 subject to a moratorium.
5 Petro-Canada was successful at the 2006 Alaska State and NPR-A lease sales, acquiring approximately 974,000 gross acres and 362,000 net acres. These leases will not be issued and effective until 2007, thus they are not included in the table above. As well, U.S. figures do not include option acreage in the Alaska Foothills.

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 common, 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, 2006
(millions of Canadian dollars)

	Petro-Canada Share of Total Work Commitments	**Petro-Canada Share of Total Work Commitments to be Incurred in 2007[1]**
Mainland Canada		
Mackenzie Delta/Corridor region	$ 14.9	$ -
East Coast offshore	15.0	8.0
International		
Northern Latin America	7.7	3.2
Northwest Europe	70.5	53.3
North Africa/Near East	23.6	23.6
Total work commitments from continuing operations	131.7	88.1
Discontinued operations	-	-
Total work commitments	$ 131.7	$ 88.1

1 Capital expenditure plan for 2007 includes provisions 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 in will expire in 2007.

LAND EXPIRIES IN 2007
(millions of acres)

	Gross[1]	Net[2]
North American Natural Gas	0.8	0.6
East Coast Oil	0.5	0.2
Oil Sands	0.2	0.1
International	-	-
Total expiries in 2007	1.5	0.9

1 Gross acres include the interests of others.
2 Net acres exclude the interests of others.

Drilling Activity

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

EXPLORATION AND DEVELOPMENT WELLS DRILLED

	2006		2005		2004	
	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	**3**	**3**	-	-	2	-
Natural gas	**18**	**14**	48	31	53	35
Dry[4]	**20**	**19**	21	15	19	14
Subtotal	**41**	**36**	69	46	74	49
Development wells[5]						
Oil	**75**	**68**	4	2	5	2
Natural gas	**551**	**413**	666	437	589	461
Dry	**9**	**6**	4	3	7	5
Subtotal	**635**	**487**	674	442	601	468
Total North American Natural Gas	**676**	**523**	743	488	675	517
EAST COAST OIL						
Exploration wells[3]						
Oil	**3**	**1**	2	1	-	-
Dry[4]	**-**	**-**	-	-	-	-
Subtotal	**3**	**1**	2	1	-	-
Development wells[5]						
Oil	**10**	**3**	13	3	17	4
Dry	**-**	**-**	-	-	-	-
Subtotal	**10**	**3**	13	3	17	4
Total East Coast Oil	**13**	**4**	15	4	17	4
OIL SANDS						
Development wells[5]						
Bitumen	**-**	**-**	46	46	-	-
Total Oil Sands	**-**	**-**	46	46	-	-

1 Gross wells are wells (excluding all service wells) in which Petro-Canada owns a working interest. This includes 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.

EXPLORATION AND DEVELOPMENT WELLS DRILLED

	2006		2005		2004	
	Gross[1]	**Net[2]**	Gross[1]	Net[2]	Gross[1]	Net[2]
INTERNATIONAL - Continuing Operations						
Exploration wells[3]						
Oil						
Northwest Europe	**-**	**-**	4	3	-	-
North Africa/Near East	**1**	**1**	2	1	2	1
Natural gas						
Northwest Europe	**1**	**-**	-	-	-	-
Northern Latin America	**-**	**-**	-	-	1	-
Dry[4]						
Northwest Europe	**2**	**-**	-	-	4	1
North Africa/Near East	**1**	**1**	4	2	1	1
Subtotal	**5**	**2**	10	6	8	3
Development wells[5]						
Oil						
Northwest Europe	**18**	**6**	4	1	9	7
North Africa/Near East	**5**	**2**	7	4	6	3
Natural gas						
Northwest Europe	**-**	**-**	1	-	1	-
Northern Latin America	**8**	**1**	-	-	-	-
Dry						
Northwest Europe	**1**	**-**	-	-	1	-
Northern Latin America	**-**	**-**	-	-	1	-
Subtotal	**32**	**9**	12	5	18	10
Total International	**37**	**11**	22	11	26	13
Total wells drilled from continuing operations	**726**	**538**	826	549	718	534
DISCONTINUED OPERATIONS						
Development wells[5]						
Oil	**-**	**-**	44	15	39	13
Dry	**-**	**-**	5	2	9	4
Total discontinued operations	**-**	**-**	49	17	48	17
Total wells drilled	**726**	**538**	875	566	766	551

1 Gross wells are wells (excluding all service wells) in which Petro-Canada owns a working interest. This includes 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

Petro-Canada is the second largest Downstream business and the "brand of choice" in Canada. In 2006, Petro-Canada accounted for approximately 13% of the total refining capacity in Canada and about 16% of total petroleum products sold in Canada.

Downstream operations include two refineries - one in Edmonton and one in Montreal - with a total daily rated capacity of 40,500 cubic metres/day (m^3/d) (255,000 b/d), a lubricants plant - the largest producer of lubricant base stocks in Canada, a network of more than 1,300 retail service stations, Canada's largest commercial road transport network of 219 locations and a robust bulk fuel sales channel.

The strategy in the Downstream business is to increase the profitability of the base business through effective capital investment and disciplined management of controllable factors. In 2007, planned Downstream capital investment will shift to growth projects as regulatory projects to produce cleaner burning fuels were completed in 2006. The Downstream business' goal is to deliver superior returns and growth, including a 12% return on capital employed (ROCE) based on a mid-cycle business environment. Key features of the strategy include:

- achieving and maintaining first quartile operating performance in all areas
- advancing Petro-Canada as the "brand of choice" for Canadian gasoline consumers
- increasing sales of high margin specialty lubricants

Refining and Supply

Petro-Canada owns and operates two refineries, with a total daily rated capacity of approximately 40,500 m^3/d at the end of 2006. This represents approximately 13% of the Canadian refining industry's total operating capacity. Petro-Canada's refineries produce a full range of refined petroleum products, including gasoline, diesel oils, heating oils, aviation fuels, heavy fuel oils, asphalts, petrochemicals and feedstock for lubricants.

Work at the Montreal and Edmonton refineries to bring new diesel desulphurization units on-stream was completed in the second quarter of 2006. Both refineries also completed major investments in 2006 to increase their capability to produce diesel fuels with better cold weather properties. The following table shows the daily rated capacity of Petro-Canada's refineries as at December 31, 2006 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 crude utilization rate at the two refineries averaged 93% in 2006, down 3% from 2005 due to the planned shutdowns to bring the new diesel desulphurization units on-stream.

RATED CAPACITY OF REFINERIES AND AVERAGE DAILY CRUDE OIL PROCESSED

(thousands of m^3/d)

	Average Volumes of Crude Oil Processed/Calendar Day			Daily Rated Capacity[1]
	Years Ended December 31,			
Refinery Location	**2006**	2005	2004	**As at December 31, 2006**
Edmonton, Alberta	**18.9**	20.8	19.6	19.9
Montreal, Quebec[2]	**18.9**	18.1	16.0	20.6
Oakville, Ontario[3]	**-**	2.0	12.6	-
Total	**37.8**	40.9	48.2	40.5

1 Daily rated capacity is based on calendar days and defined 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 Includes capacity expansion completed at Montreal in December 2004 and rated in 2005 at an additional 3,900 m^3/d.

3 The second of the two crude processing trains at the Oakville refinery was permanently closed on April 11, 2005. This was part of the previously announced consolidation of Eastern Canada refinery operations. Prior to such closure, daily rated capacity was 7,000 m^3/d.

With the major regulatory projects completed, Petro-Canada is well positioned with the supply capability to optimize profitability within a range of future business scenarios.

Looking forward, Petro-Canada intends to take advantage of the trend toward increased production of cheaper, heavier crudes. In 2006, Downstream completed detailed engineering work and started construction to convert the Edmonton refinery to process 100% bitumen-based feedstock and furthered work to evaluate the feasibility of adding a coker to the Montreal refinery.

Edmonton Refinery

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

At the Edmonton refinery, Petro-Canada is building new crude and vacuum units, and expanding coker capacity and sulphur removal capability to upgrade and refine bitumen-based feedstock. The new configuration, targeted for completion in 2008, will allow the refinery to directly upgrade an Athabasca blend feed of 5,500 m^3/d (comprised of 4,100 m^3/d of bitumen and 1,400 m^3/d of diluent) 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 Oil Sands in the Upstream section of this AIF for long-term arrangement for the supply of bitumen and sour crude oil feedstock 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 feedstock. The refinery produces gasoline, distillates, asphalts, petrochemicals, solvents and feedstock for lubricants.

Petro-Canada continues its assessment of the potential addition of a 25,000 b/d coker unit, which would allow the Montreal refinery to leverage lower cost heavier crude feedstock and upgrade existing lower value asphalt and heavy fuel oil into diesel and gasoline fuel. The assessment is expected to be completed in 2007, at which time a decision will be made on whether to proceed with the project.

Oakville Refinery

As part of the Eastern Canada refining and supply consolidation project, the former Oakville refinery completed a phased shutdown of its operations during the second quarter of 2005. Oakville's terminal facilities were expanded to handle receipt of finished light oil product from Montreal via the TNPI pipeline. In total, the expanded Oakville terminal, in combination with existing industry terminal facilities in north Toronto, is capable of receiving TNPI's full light oil capacity of 10,000 m^3/d, replacing the light oil that was produced by the Oakville refinery operations.

ParaChem Chemicals Plant

Petro-Canada holds a 51% working interest in ParaChem Chemicals L.P., which owns and operates a petrochemicals plant located adjacent to the Montreal refinery. The plant primarily produces up to 350,000 metric tons per year of paraxylene (PX), which is used to manufacture polyester textiles and plastic bottles. ParaChem also produces benzene, hydrogen and heavy aromatics. The 75-hectare plant site is located in Montreal's industrial district, with access to pipelines, the sea and rail shipping facilities. Its hydrocarbon storage capacity exceeds 300 million litres.

Petro-Canada currently supplies mixed xylenes and toluene to ParaChem. The integration of the Parachem plant with the Montreal refinery provides several synergies, including the ability to capture more of the petrochemicals value chain through vertical integration. In 2006, a tunnel and pipeline were completed between the Montreal refinery and the ParaChem plant, facilitating the safe and cost-effective transfer of products. Additional pipelines will be added in 2007. Parachem continues to assess various long-term growth projects that would leverage its strategic position in Quebec's petrochemical market.

Supply and Distribution

Petro-Canada purchases crude oil and other refinery feedstock 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.

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.

Petro-Canada operates an extensive distribution network, using 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, one crude pipeline and a joint venture interest in one major refined products terminal. Petro-Canada also operates 11 major refined products terminals across Canada.

Sales and Marketing

Petro-Canada is the second largest marketer of petroleum products in Canada. In 2006, Petro-Canada's petroleum product sales represented approximately 16% of total petroleum products sold in Canada. Petro-Canada markets a full range of petroleum products, including gasoline, diesel oils, heating oils, aviation fuels, heavy fuel oils, asphalts, lubricants, petrochemical feedstock and liquefied petroleum gases. Petro-Canada also generates non-petroleum revenue from convenience stores, car washes, and automotive repair and maintenance services. During 2006, the Company focused on profitable growth through initiatives directed at the retail and PETRO-PASS truck stop networks.

AVERAGE DAILY SALES OF PETROLEUM PRODUCTS

(thousands of m^3/d)

	Years Ended December 31,		
	2006	2005	2004
Gasoline[1]	**24.2**	24.4	24.7
Middle distillates[2]	**19.6**	19.7	20.2
Other[3]	**8.7**	8.7	11.7
Total	**52.5**	52.8	56.6

1 Includes motor and aviation gasoline.
2 Includes diesel oils, heating oils and aviation jet fuels.
3 Includes heavy fuel oils, asphalts, lubricants, liquefied petroleum gases, petrochemical feedstock 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 Canadian dollars)

	Years Ended December 31,		
	2006	2005	2004
Gasoline[1]	**$ 5,481**	$ 5,027	$ 4,218
Middle distillates[2]	**4,537**	4,244	3,262
Other[3]	**2,363**	2,081	1,954
Total	**$ 12,381**	$ 11,352	$ 9,434

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

Retail

At December 31, 2006, Petro-Canada's network of retail sites consisted of 1,312 outlets across Canada, of which 819 were Company-controlled and the balance were controlled by third parties. Independent dealers and agents operate virtually all 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 retail market. In 2006, Petro-Canada led the industry in key urban market metrics and continued to improve the fundamentals of the business with more than 90% of the re-imaging program now complete. Advancement of this program has enabled the realization of industry-leading throughputs, with annual gasoline sales from re-imaged sites within Petro-Canada's network averaging more than 7 million litres per site. The Company has extended this new image program to independent retailers and, to date, nearly 62% 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 the advancement of previously launched innovative product developments and new product firsts, including Citi Petro-Points MasterCard, the first general-purpose credit card in North America to offer cardholders an instant discount on gasoline, and 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 8% year-over-year sales growth of its convenience store business and 5% increase in same-store sales in 2006, compared with 2005.

Wholesale

Petro-Canada sells petroleum products into farm, home heating, paving, small industrial, commercial and truck markets. This category accounted for approximately 51% of total Downstream sales volumes. Petro-Canada is the leading national marketer to the commercial road transport segment in Canada with 219 PETRO-PASS sites. The Company also sells large volumes of petroleum products directly to large industrial and commercial customers and independent marketers.

The Company's focus has been on improving its sales mix in the commercial road transport and bulk fuels channels. In 2006, Petro-Canada continued to expand and upgrade the network.

Lubricants

The lubricants centre 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 900 million litres. In early 2006, a fire occurred at the Mississauga lubricants plant. The Company's investigation indicated that the fire occurred during a routine maintenance procedure in a fractionation section of the plant. The lubricants plant operated at 50% capacity following the fire. Repairs were completed and production on the unit was restored to pre-incident levels in March 2006. In June, the 25% expansion of the lubricants plant came on-stream to support the growth of its high margin, specialty lubricants business.

The lubricants plant uses 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 feedstock into lubricating oil-based stocks with the highest level of purity of any base stocks in Canada. Advancing lubricant technology and growing 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 product-driven strategy is to grow volume in high margin sales and improve plant reliability. In 2006, Petro-Canada continued to focus on optimizing operations and maintenance procedures based on industry best practices. Lubricants sales in 2006 totalled 722 million litres, a decrease of approximately 7%, compared with sales volume of 779 million litres in 2005. The decrease in sales volumes was primarily due to the fire at the plant in early 2006. Sales in high margin product segments represented 75% of total sales by year-end 2006. Lubricants continue 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 like those produced at the Mississauga lubricants plant.

Pipelines

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

Link to Petro-Canada's Corporate and Strategic Priorities

The Downstream business is aligned with Petro-Canada's strategic priorities as outlined by its progress in 2006 and goals for 2007.

	2006 RESULTS	2007 GOALS
DELIVERING PROFITABLE GROWTH WITH A FOCUS ON OPERATED, LONG-LIFE ASSETS	• completed lubricant plant 25% expansion • completed detailed engineering and 18% of the Edmonton refinery conversion project	• continue the Edmonton refinery conversion project to enable the planned startup in 2008 • complete Montreal coker feasibility study for investment decision in 2007 • continue to invest in smaller scale refinery yield and reliability improvement projects • continue to integrate the Montreal refinery and the ParaChem Chemicals L.P. plant
DRIVING FOR FIRST QUARTILE OPERATION OF OUR ASSETS	• achieved a combined reliability index of 95 at the Company's two refineries, above 90 for a second year in a row • completed multi-year project to produce cleaner burning fuels at refineries • maintained leading share of major retail urban market • grew convenience store sales by 8% and same-store sales by 5%, compared with 2005 • achieved 75% high margin lubricant sales volume mix	• continue to focus on safety and refinery reliability • increase retail non-petroleum revenue • grow high margin lubricants sales volume
CONTINUING TO WORK AT BEING A RESPONSIBLE COMPANY	• reduced TRIF by 3%, compared with 2005 • reduced regulatory compliance exceedances by 17%, compared with 2005	• maintain focus on TRIF and regulatory compliance exceedances • meet provincial ethanol regulations • continue focus on community relations, including establishment of Community Liaison Committee in Montreal • continue to look for partnerships with Aboriginal communities on retail opportunities

Research and Development

Petro-Canada owns a research facility at Sheridan Park in Mississauga, Ontario, where the Company conducts research directed toward the development of new lubricant products and product support for the Company's customers.

The Company continues to support advancement of new bitumen recovery technologies and processes in its Oil Sands business.

In 2006, Petro-Canada's total expenditures on research and development activities were approximately $34 million.

Human Resources

As at December 31, 2006, Petro-Canada and its wholly owned subsidiaries had 5,156 employees, compared with 4,816 employees as at December 31, 2005. Of the year-end 2006 employees, 1,347 employees were employed in the North American upstream businesses, 190 employees were in International and 2,487 employees were in Downstream. The remaining 1,132 employees were corporate support staff. Of the upstream employees, 168 employees were in East Coast Oil, 295 employees were in Oil Sands and 884 employees were in North American Natural Gas. Seventy-three of the upstream employees, 171 of the International employees, 28 of the Downstream employees and 168 of the corporate support staff employees were employed outside of Canada. Approximately 23% of Petro-Canada's employees were covered by collective bargaining agreements. Approximately 91% of the Company's unionized employees were members of the Communications Energy and Paperworkers Union (CEP), which represents refinery, marketing, gas plant and offshore production workers. Three-year collective bargaining agreements with most CEP locals expired on January 31, 2007. Negotiations are currently in progress.

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 (a copy of which is available under the Company's SEDAR profile at www.sedar.com), 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, is recognized as being ethically, socially and environmentally responsible, is welcomed by the communities in which Petro-Canada operates and helps facilitate 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[1] and standards. Petro-Canada periodically reviews each business unit or Shared Services unit based on risk 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 reviews environment, health and safety performance throughout the year.

At Petro-Canada, investing in communities is an integral part of the way the Company does business. Petro-Canada works with communities in the Company's key business locations to ensure its presence generates value and makes a difference for its neighbours. The Company invests in large scale initiatives that provide significant benefits at a national level, as well as in grassroots programs and services at the local level. Following a detailed strategic review of its community partnerships program in 2006, the Company will direct its funding to education, the environment, and local community support.

1 Petro-Canada's TLM framework is a systematic approach to identify, assess and control operational risk.

CASH AND IN-KIND CONTRIBUTIONS OF MORE THAN $20 MILLION IN 2006

Highlights

In 2006, Petro-Canada invested nearly $10.7 million to support Canadian Olympic and Paralympic athletes and coaches through the Company's Olympic Torch Scholarship Legacy Fund and other programs. An additional $6.2 million was invested in local community support to strengthen the communities where employees live and work.

Employees and the Company donated more than $3 million to United Way campaigns across North America in 2006. Through its Volunteer Energy Program, Petro-Canada provided 498 grants totalling $239,748[1] 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 $1.8 million by the end of 2006. In addition to the grants, Petro-Canada employees and retirees contributed more than 4,300 hours of volunteer time to 112 projects for non-profit organizations through Petro-Canada's year-round Days of Caring initiatives.

To learn more about Petro-Canada's corporate responsibility performance, please access the annual Report to the Community available on the Company's website (www.petro-canada.ca). The 2006 Report is expected to become available in the second quarter of 2007.

	Years ended December 31,					
(millions of Canadian dollars)		**2006**		2005		2004
Local Community Support[1]	**$**	**6.2**	$	3.6	$	3.1
United Way[2]		**1.2**		1.0		0.8
Olympic/Paralympic		**10.7**		0.3		0.5
International		**-**		-		0.1
Education		**1.5**		1.8		1.6
Environment		**0.6**		0.6		0.6
Total	**$**	**20.2**	$	7.3	$	6.7

1 Includes community contributions from both operating units and the community partnerships program.
2 Includes Company contributions only.

Environmental Expenditures

In 2006, Petro-Canada's environmental capital and operating expenditures totalled $501 million, compared with $856 million in 2005 and $651 million in 2004. The decrease in 2006 expenditures mainly reflected the completion of Downstream projects to meet new federal regulations for sulphur limits in 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 2006.

ENVIRONMENTAL COSTS - YEAR ENDED DECEMBER 31, 2006
(millions of Canadian dollars)

		Capital		Operating Expense		Total
Upstream	$	68	$	106	$	174
Downstream		298		29		327
Total environmental costs	$	366	$	135	$	501

More detailed information on the Company's policies and performance relative to the environment will be included in the annual Report to the Community, expected to become available on the Company's website (www.petro-canada.ca) in the second quarter of 2007.

1 In previous years, the reported year-end figures represented volunteer grants only; however, in 2006, they include volunteer, teams for charity and alumni matching grants.

SELECT FINANCIAL DATA

CONSOLIDATED FINANCIAL INFORMATION

(millions of Canadian dollars, except per share[1] amounts)		Years Ended December 31, 2006		2005		2004
Statement of earnings data						
Revenue						
Operating	**$**	**18,911**	$	17,585	$	14,270
Investment and other income (expense)		**(242)**		(806)		(312)
Total revenue		**18,669**		16,779		13,958
Earnings from continuing operations before income taxes		**3,972**		3,402		3,090
Provision for income taxes		**2,384**		1,709		1,392
Net earnings from continuing operations		**1,588**		1,693		1,698
Net earnings from discontinued operations		**152**		98		59
Net earnings	**$**	**1,740**	$	1,791	$	1,757
Earnings						
North American Natural Gas	**$**	**402**	$	660	$	500
East Coast Oil		**934**		775		711
Oil Sands		**245**		112		120
International		**22**		453		313
Downstream		**463**		398		310
Shared Services		**(264)**		(250)		(125)
Operating earnings from continuing operations[2,3]		**1,802**		2,148		1,829
Foreign currency translation gain		**1**		73		63
Unrealized loss on Buzzard derivative contracts		**(240)**		(562)		(205)
Gain on sale of assets		**25**		34		11
Discontinued operations		**152**		98		59
Net earnings	**$**	**1,740**	$	1,791	$	1,757
Earnings per share from continuing operations - basic	**$**	**3.15**	$	3.27	$	3.21
- diluted		**3.11**		3.22		3.17
Earnings per share - basic		**3.45**		3.45		3.32
- diluted		**3.41**		3.41		3.28
Dividends per share		**0.40**		0.33		0.30
Cash flow from continuing operating activities before changes in non-cash working capital[3]		**3,687**		3,787		3,425
Balance sheet data (at end of year)						
Total assets		**22,646**		20,655		18,136
Debt		**2,894**		2,913		2,580
Cash and cash equivalents[4]		**499**		789		170
Shareholders' equity		**10,441**		9,488		8,739
Average capital employed[4]	**$**	**12,868**	$	11,860	$	10,533

1 Per share amounts are quoted on a post-stock dividend basis reflecting the stock dividend declared in July 2005.
2 Operating earnings, which represent net earnings excluding gains or losses on foreign currency translation, disposal of assets and the unrealized gains or losses on Buzzard derivative contracts, is used by the Company to evaluate operating performance.
3 Operating earnings and cash flow do not have any standardized meaning prescribed by Canadian GAAP and, therefore, may not be comparable to the calculation of similar measures for other companies.
4 Includes discontinued operations.

QUARTERLY INFORMATION

(millions of Canadian dollars, except per share amounts)

	2006 Three Months Ended				2005 Three Months Ended			
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	Mar. 31	June 30	Sept. 30	Dec. 31
Total revenue from continuing operations	**$ 4,188**	**$ 4,730**	**$ 5,201**	**$ 4,550**	$ 3,275	$ 3,945	$ 4,721	$ 4,838
Earnings								
Upstream								
North American Natural Gas	**$ 139**	**$ 97**	**$ 75**	**$ 91**	$ 103	$ 117	$ 156	$ 284
East Coast Oil	**229**	**254**	**190**	**261**	169	208	218	180
Oil Sands	**(19)**	**101**	**108**	**55**	(19)	34	82	15
International	**(132)**	**61**	**60**	**33**	105	93	104	151
Downstream	**73**	**136**	**176**	**78**	113	80	98	107
Shared Services	**(88)**	**(117)**	**(12)**	**(47)**	(44)	(56)	(61)	(89)
Operating earnings from continuing operations	**202**	**532**	**597**	**471**	427	476	597	648
Foreign currency translation gain (loss)	**(1)**	**61**	**(1)**	**(58)**	(4)	8	74	(5)
Unrealized gain (loss) on Buzzard derivative contracts	**(149)**	**(137)**	**79**	**(33)**	(313)	(171)	(85)	7
Gain on sale of assets	**2**	**16**	**3**	**4**	-	9	7	18
Discontinued operations	**152**	**-**	**-**	**-**	8	23	21	46
Net earnings	**$ 206**	**$ 472**	**$ 678**	**$ 384**	$ 118	$ 345	$ 614	$ 714
Earnings per share from continuing operations[1]								
Basic	**$ 0.11**	**$ 0.93**	**$ 1.36**	**$ 0.77**	$ 0.21	$ 0.62	$ 1.14	$ 1.29
Diluted	**$ 0.10**	**$ 0.92**	**$ 1.34**	**$ 0.76**	$ 0.21	$ 0.61	$ 1.13	$ 1.28
Earnings per share[1]								
Basic	**$ 0.40**	**$ 0.93**	**$ 1.36**	**$ 0.77**	$ 0.23	$ 0.66	$ 1.19	$ 1.38
Diluted	**$ 0.40**	**$ 0.92**	**$ 1.34**	**$ 0.76**	$ 0.22	$ 0.66	$ 1.17	$ 1.36

1 Per share amounts are quoted on a post-stock dividend basis reflecting the stock dividend declared in July 2005.

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 Canadian dollars)

		2006		2005		2004
Exploration						
North American Natural Gas	**$**	**160**	$	173	$	157
East Coast Oil		**3**		12		-
Oil Sands		**6**		32		15
International						
Northwest Europe		**37**		37		48
North Africa/Near East		**37**		29		19
Northern Latin America		**3**		7		3
Total exploration		**246**		290		242
Development						
North American Natural Gas		**523**		496		419
East Coast Oil		**253**		302		275
Oil Sands		**269**		432		381
International						
Northwest Europe		**551**		525		322
North Africa/Near East		**83**		70		71
Northern Latin America		**49**		28		22
Total development		**1,728**		1,853		1,490
Property acquisitions						
North American Natural Gas		**105**		44		90
Oil Sands		**102**		308		1
International						
Northwest Europe		**-**		-		1,222
Total property acquisitions		**207**		352		1,313
Downstream						
Refining and supply		**1,038**		883		656
Sales, marketing and other		**142**		108		171
Lubricants		**49**		62		12
Total Downstream		**1,229**		1,053		839
Shared Services		**24**		12		9
Total capital expenditures on property, plant and equipment and exploration from continuing operations		**3,434**		3,560		3,893 [1]
Discontinued operations		**1**		46		62
Total capital expenditures on property, plant and equipment and exploration	**$**	**3,435**	$	3,606	$	3,955[1]

1 Excludes U.S. Rockies acquisition of Prima Energy Corporation totalling $644 million net of acquired cash.

In 2007, spending on new growth projects is expected to increase. More than 60% of planned capital expenditures support delivering profitable new growth, and funding exploration and new ventures. This estimate is up from nearly 53% in these categories in 2006. The remaining 40% of the 2007 planned capital expenditures are directed toward replacing reserves in core areas, enhancing existing assets, improving base business profitability and complying with regulations. The regulatory compliance portion of the program was greater in 2006, primarily reflecting expenditures to produce cleaner burning fuels at Downstream refineries.

2007 Capital Outlook		*(millions of Canadian dollars)*
Regulatory compliance	$	100
Enhancing existing assets		240
Improving base business profitability		160
Reserves replacement in core areas		1,025
New growth projects		2,020
Exploration and new ventures for long-term growth		515
Total continuing operations	$	4,060

Capital Investment by Business - 2007 Outlook		*(millions of Canadian dollars)*
Upstream		
North American Natural Gas	$	790
East Coast Oil		210
Oil Sands		770
International		865
Subtotal		2,635
Downstream		
Refining and Supply		1,215
Sales and Marketing		150
Lubricants		25
Subtotal		1,390
Shared Services		35
Total Continuing Operations	$	4,060

Dividends

Petro-Canada regularly 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 growth opportunities. The second priority is to return funds to shareholders through dividends and the share buyback program. Consistent with the second priority, the Company declared, on December 14, 2006, a 30% increase in the quarterly dividend to $0.13/share, commencing with the dividend payable on April 1, 2007. Total dividends paid in 2006 were $201 million, compared with $181 million in 2005 and $159 million in 2004.

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, 2006, there were 497,538,385 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. 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 shareholders are entitled to receive any dividend declared by the Board of Directors on the common shares and to participate in 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 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. Additional restrictions include provisions for suspension of voting rights, forfeiture of dividends, prohibitions against share transfer, compulsory sale of shares, and 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, and issuing or registering a transfer of, any voting shares if a contravention of the individual ownership restrictions results.

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 fulfill 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.

Credit Ratings

The following table shows the ratings issued by the rating agencies noted therein as of December 31, 2006. 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 (Moody's)	Standard & Poor's (S&P)	Dominion Bond Rating Service (DBRS)
Outlook	Stable	Stable	Stable
Senior unsecured	Baa2	BBB	A (low)
Short term	-	-	R-1 (low)

Moody's credit ratings are on a long-term debt rating scale that ranges from Aaa to C, which represents the range from highest to lowest quality of such securities rated. According to the Moody's rating system, debt securities rated "Baa" are considered as medium grade obligations (e.g. they are neither highly protected nor poorly secured). Interest payments and principal security appear adequate for the present, but certain protective elements may be lacking or may be characteristically unreliable over any great length of time. Such bonds lack outstanding investment characteristics and, in fact, have speculative characteristics as well.

Moody's applies numerical modifiers 1, 2 and 3 in each generic rating classification from Aa through Caa in its corporate bond rating system. The modifier 1 indicates that the issue ranks in the higher end of its generic rating category, the modifier 2 indicates a mid-range ranking and the modifier 3 indicates that the issue ranks in the lower end of its generic rating category.

S&P's credit ratings are on a long-term debt rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. According to the S&P rating system, an obligation rated "BBB" exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation. The ratings from AA to CCC may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories.

DBRS' credit ratings are on a long-term debt rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. According to the DBRS rating system, bonds and long-term debt rated A are of satisfactory credit quality. Protection of interest and principal is still substantial, but the degree of strength is less than with AA rated entities. While a respectable rating, entities in the "A" category are considered to be more susceptible to adverse economic conditions and have greater cyclical tendencies than higher rated companies. The ratings from AA to C may be modified by the addition of a "high" or "low" grade to indicate the relative standing of a credit within a particular rating category.

DBRS' short-term credit ratings are on a short-term debt rating scale that ranges from R-1 to D, which represents the range from highest to lowest quality of such securities rated. The ratings from R-1 to R-3 may be modified by the addition of a "high," "mid" or "low" grade to indicate the relative standing of a credit within a particular rating category. According to the DBRS rating system, short-term debt rated R-1(low) is of satisfactory credit quality. The overall strength and outlook for key liquidity, debt and profitability ratios is not normally as favourable as with higher rating categories, but these considerations are still respectable. Any qualifying negative factors that exist are considered manageable, and the entity is normally of sufficient size to have some influence in its industry.

MARKET FOR SECURITIES

Trading Price and Volume

The Company's outstanding share capital is comprised of common shares, and each common share carries one vote. The Company's common shares trade on the Toronto Stock Exchange (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 2006 on a monthly basis.

PETRO-CANADA SHARE TRADING ACTIVITY ON THE TSX AND THE NYSE IN 2006

	Toronto Stock Exchange				New York Stock Exchange			
	Share Price Trading Range (Canadian dollars per share)			Share Volume	Share Price Trading Range (U.S. dollars per share)			Share Volume
	High	Low	Close	(millions)	High	Low	Close	(millions)
2006								
January	$ 55.42	$ 48.00	$ 54.51	39.8	$ 48.33	$ 41.20	$ 47.93	8.9
February	58.59	51.54	52.06	55.6	51.08	44.59	45.76	14.2
March	56.54	51.65	55.38	44.9	49.11	44.60	47.59	10.7
April	57.80	54.71	55.00	32.5	51.11	47.92	49.18	8.0
May	55.40	46.58	50.02	49.1	50.11	41.69	45.97	14.7
June	52.96	46.11	52.96	42.6	47.41	41.31	47.41	15.5
July	53.30	49.76	50.58	27.3	48.24	43.73	44.75	9.4
August	52.20	46.69	47.20	35.7	46.53	42.06	42.72	9.3
September	48.35	42.38	45.01	48.1	43.60	37.78	40.33	13.6
October	48.80	41.91	47.88	41.5	43.54	37.37	42.59	13.3
November	51.70	47.24	51.49	35.5	45.48	41.67	45.20	10.3
December	$ 51.64	$ 47.00	$ 47.75	31.7	$ 45.18	$ 40.78	$ 41.04	10.6

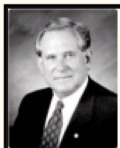
Prior Sales

Petro-Canada had no debt issuances in 2006.

DIRECTORS AND OFFICERS

Directors

The following describes information concerning Directors of the Company. It should be noted that Angus A. Bruneau retires from the Board of Directors following the close of the annual general meeting (April 24, 2007). 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 1, 2007.



ANGUS A. BRUNEAU, O.C.
Independent[1]
Age: 71
St. John's, Newfoundland and Labrador, Canada
Director since 1996

Angus Bruneau retired in May 2006 as Chairman of the Board of Directors of Fortis Inc. (utilities and services corporation). He also serves as a Director of Aurora Energy Resources Inc. He is an executive member of a number of not-for-profit organizations, including Sustainable Development Technology Canada and Canadian Institute for Child Health. Dr. Bruneau is a Professional Engineer and holds a Bachelor of Science, D.Eng, and a PhD.

Board and Committee Membership	Attendance	
Board of Directors	8 of 9	89%
Environment, Health and Safety Committee (Chair)	3 of 3	100%
Audit, Finance and Risk Committee	7 of 7	100%

Securities Held

Year	Common Shares[2]	DSUs[3]	Total of Common Shares and DSUs	Total Market Value of Common Shares and DSUs[4]	Minimum Required[5]
2006	5,539	10,922	16,461	$ 627,412	$300,000
2005	5,527	10,819	16,346	$ 786,013	

Options Held: None. Non-employee Directors are not eligible to participate in the Company's stock option plan.

Other Public Board Directorships: None

GAIL COOK-BENNETT
Independent[1]
Age: 66
Toronto, Ontario, Canada
Director since 1991

Gail Cook-Bennett is Chairperson of the Canada Pension Plan Investment Board (public pension plan investment). Dr. Cook-Bennett earned a Doctorate in Economics and holds a Doctor of Laws (honoris causa) from Carleton University. She is a Fellow of the Institute of Corporate Directors.

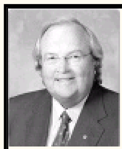
Board and Committee Membership	Attendance	
Board of Directors	9 of 9	100%
Audit, Finance and Risk Committee	7 of 7	100%
Pension Committee (Chair)	2 of 2	100%

Securities Held

Year	Common Shares[2]	DSUs[3]	Total of Common Shares and DSUs	Total Market Value of Common Shares and DSUs[4]	Minimum Required[5]
2006	4,098	20,151	24,249	$ 1,157,890	$300,000
2005	4,098	19,998	24,096	$ 874,303	

Options Held: None. Non-employee Directors are not eligible to participate in the Company's stock option plan.

Other Public Board Directorships:[6] Emera Inc. and Manulife Financial Corporation



RICHARD J. CURRIE, O.C.[8]
Independent[1]
Age: 69
Toronto, Ontario, Canada
Director since 2003

Dick Currie is Chairman of the Board of Bell Canada Enterprises (telecommunications). From 1996 to 2002, he was President and Director of George Weston Limited (food processing) and from 1976 to 2000, President and Director of Loblaw Companies Limited (food and distribution). Mr. Currie holds a Bachelor of Engineering and a Master of Business Administration. He is the Chancellor of the University of New Brunswick and a Fellow of the Institute of Corporate Directors.

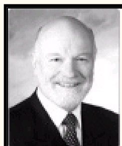
Board and Committee Membership	Attendance	
Board of Directors	7 of 9	78%
Management Resources and Compensation Committee	3 of 4	75%
Pension Committee	1 of 2	50%

Securities Held

Year	Common Shares[2]	DSUs[3]	Total of Common Shares and DSUs	Total Market Value of Common Shares and DSUs[4]	Minimum Required[5]
2006	50,000	3,165	53,165	$ 2,538,629	$300,000
2005	20,000	3,146	23,146	$ 1,040,467	

Options Held: None. Non-employee Directors are not eligible to participate in the Company's stock option plan.

Other Public Board Directorships:[6] BCE Inc.



CLAUDE FONTAINE, Q.C.
Independent[1]
Age: 65
Montreal, Quebec, Canada
Director since 1987

Claude Fontaine is counsel to Ogilvy Renault LLP (barristers and solicitors) and, prior to that, he was a Partner of the firm. He serves as Lead Director for Optimum General Inc. and is a Director of the Institute of Corporate Directors (Chair of the Quebec Chapter) and the Montreal Heart Institute Foundation. Mr. Fontaine holds a Bachelor of Arts, Licence in Law (LL.L), and an Institute of Corporate Directors certification.

Board and Committee Membership	Attendance	
Board of Directors	9 of 9	100%
Environment, Health and Safety Committee	3 of 3	100%
Management Resources and Compensation Committee (Chair)	4 of 4	100%

Securities Held

Year	Common Shares[2]	DSUs[3]	Total of Common Shares and DSUs	Total Market Value of Common Shares and DSUs[4]	Minimum Required[5]
2006	15,929	30,221	46,150	$ 2,203,663	$300,000
2005	15,926	28,340	44,266	$ 1,711,042	

Options Held: None. Non-employee Directors are not eligible to participate in the Company's stock option plan.

Other Public Board Directorships: Optimum General Inc.

PAUL HASELDONCKX
Independent[1]
Age: 58
Essen, Germany
Director since 2002

Paul Haseldonckx, Corporate Director, is the past Chairman of the Executive Board of Veba Oil & Gas GmbH (integrated oil and gas) and its predecessor companies. Mr. Haseldonckx holds a Master of Science.

Board and Committee Membership	Attendance	
Board of Directors	9 of 9	100%
Audit, Finance and Risk Committee	7 of 7	100%
Environment, Health and Safety Committee	3 of 3	100%

Securities Held

Year	Common Shares[2]	DSUs[3]	Total of Common Shares and DSUs	Total Market Value of Common Shares and DSUs[4]	Minimum Required[5]
2006	6,022	6,119	12,141	$ 579,733	$300,000
2005	3,001	6,076	9,077	$ 347,553	

Options Held: None. Non-employee Directors are not eligible to participate in the Company's stock option plan.

Other Public Board Directorships: None

THOMAS E. KIERANS, O.C.[8]
Independent[1]
Age: 66
Toronto, Ontario, Canada
Director since 1991

Tom Kierans is Chairman of the Canadian Journalism Foundation (non-profit), prior to which he was Chairman of CSI Global Markets. Mr. Kierans holds a Bachelor of Arts (Honours) and a Master of Business Administration (Finance, Dean's Honours List), and is a Fellow of the Canadian Institute of Corporate Directors. He serves as a Director of Mount Sinai Hospital, the Canadian Institute for Advanced Research and the Social Sciences and Humanities Research Council. Mr. Kierans also sits on a number of advisory boards of for-profit and not-for-profit organizations, including Lazard (Canada) and the Schulich School of Business, York University.

Board and Committee Membership	Attendance	
Board of Directors	8 of 9	89%
Corporate Governance and Nominating Committee	4 of 4	100%
Management Resources and Compensation Committee	3 of 4	75%

Securities Held

Year	Common Shares[2]	DSUs[3]	Total of Common Shares and DSUs	Total Market Value of Common Shares and DSUs[4]	Minimum Required[5]
2006	50,000	6,707	56,707	$ 2,707,759	$300,000
2005	40,900	6,659	47,559	$ 2,135,456	

Options Held: None. Non-employee Directors are not eligible to participate in the Company's stock option plan.

Other Public Board Directorships:[6] Manulife Financial Corporation

BRIAN F. MacNEILL, C.M.
Independent[1]
Age: 67
Calgary, Alberta, Canada
Director since 1995

Brian MacNeill is the Chairman of the Board of Directors of Petro-Canada. Mr. MacNeill is a Certified Public Accountant and holds a Bachelor of Commerce. He is a member of the Canadian Institute of Chartered Accountants and the Financial Executives Institute. He is also a Fellow of the Alberta and Ontario Institutes of Chartered Accountants and of the Institute of Corporate Directors. He is Chair of the Board of Governors of the University of Calgary.

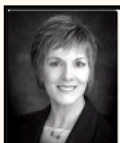
Board and Committee Membership	Attendance	
Board of Directors (Chair) As Chair of the Board, Mr. MacNeill is an *ex-officio* member of all Committees.	9 of 9	100%

Securities Held

Year	Common Shares[2]	DSUs[3]	Total of Common Shares and DSUs	Total Market Value of Common Shares and DSUs[4]	Minimum Required[5]
2006	10,200	42,573	52,773	$ 2,519,911	$300,000
2005	10,200	37,266	47,466	$ 1,748,837	

Options Held: None. Non-employee Directors are not eligible to participate in the Company's stock option plan.

Other Public Board Directorships: Toronto-Dominion Bank, Telus Corp. and West-Fraser Timber Co. Ltd.



MAUREEN McCAW
Independent[1]
Age: 52
Edmonton, Alberta, Canada
Director since 2004

Maureen McCaw is immediate past President of Leger Marketing (Alberta) (marketing research), formerly Criterion Research Corp., a company she founded in 1986. Ms. McCaw holds a Bachelor of Arts from the University of Alberta. She is a past Chair of the Edmonton Chamber of Commerce and also serves on a number of Alberta Boards and advisory committees.

Board and Committee Membership	Attendance	
Board of Directors	8 of 9	89%
Corporate Governance and Nominating Committee	2 of 4	50%
Pension Committee	2 of 2	100%

Securities Held

Year	Common Shares[2]	DSUs[3]	Total of Common Shares and DSUs	Total Market Value of Common Shares and DSUs[4]	Minimum Required[5]
2006	1,744	4,757	6,501	$ 310,423	$300,000
2005	1,360	3,314	4,674	$ 176,650	

Options Held: None. Non-employee Directors are not eligible to participate in the Company's stock option plan.

Other Public Board Directorships: None

PAUL D. MELNUK
Independent[1]
Age: 52
St. Louis, Missouri, USA
Director since 2000

Paul Melnuk is Chairman and Chief Executive Officer of Thermadyne Holdings Corporation (industrial products) and Managing Partner of FTL Capital Partners LLC (merchant banking). He is past President and Chief Executive Officer of Bracknell Corporation and Barrick Gold Corporation. Mr. Melnuk holds a Bachelor of Commerce. He is a member of the Canadian Institute of Chartered Accountants (CICA) and of the World Presidents' Organization, St. Louis chapter.

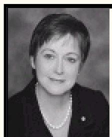
Board and Committee Membership	Attendance	
Board of Directors	9 of 9	100%
Audit, Finance and Risk Committee (Chair)	7 of 7	100%
Environment, Health and Safety Committee	3 of 3	100%

Securities Held

Year	Common Shares[2]	DSUs[3]	Total of Common Shares and DSUs	Total Market Value of Common Shares and DSUs[4]	Minimum Required[5]
2006	4,400	19,624	24,024	$ 1,147,146	$300,000
2005	4,400	15,904	20,304	$ 748,541	

Options Held: None. Non-employee Directors are not eligible to participate in the Company's stock option plan.

Other Public Board Directorships: Thermadyne Holdings Corporation



GUYLAINE SAUCIER, F.C.A, C.M.[7]
Independent[1]
Age: 60
Montreal, Quebec, Canada
Director since 1991

Guylaine Saucier, Corporate Director, is a former Chair of the Board of Directors of the Canadian Broadcasting Corporation, a former Director of the Bank of Canada, a former Chair of the Canadian Institute of Chartered Accountants (CICA), a former Director of the International Federation of Accountants and former Chair of the Joint Committee on Corporate Governance established by the CICA, the Toronto Stock Exchange and the Canadian Venture Exchange. She was also the first woman to serve as President of the Quebec Chamber of Commerce. Mme Saucier obtained a Bachelor of Arts from Collège Marguerite-Bourgeois and a Bachelor of Commerce from the École des Hautes Études Commerciales, Université de Montréal. She is a Fellow of the Institute of Chartered Accountants and a member of the Order of Canada. In 2004, she received the Fellowship Award from the Institute of Corporate Directors.

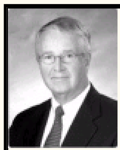
Board and Committee Membership	Attendance	
Board of Directors	9 of 9	100%
Corporate Governance and Nominating Committee (Chair)	4 of 4	100%
Pension Committee	2 of 2	100%

Securities Held

Year	Common Shares[2]	DSUs[3]	Total of Common Shares and DSUs	Total Market Value of Common Shares and DSUs[4]	Minimum Required[5]
2006	6,520	34,961	41,481	$ 1,980,718	$300,000
2005	6,520	31,571	38,091	$ 1,382,623	

Options Held: None. Non-employee Directors are not eligible to participate in the Company's stock option plan.

Other Public Board Directorships: AXA Assurance Inc., Bank of Montreal, CHC Helicopter Corp. and Groupe Areva



JAMES W. SIMPSON
Independent[1]
Age: 63
Danville, California, USA
Director since 2004

Jim Simpson is past President of Chevron Canada Resources (oil and gas). He serves as Lead Director for Canadian Utilities Limited and is on its Audit, Governance and, Compensation Committees. Mr. Simpson holds a Bachelor of Science and Master of Science, and graduated from the Program for Senior Executives at M.I.T's Sloan School of Business. He is also past Chairman of the Canadian Association of Petroleum Producers and past Vice-Chairman of the Canadian Association of the World Petroleum Congresses.

Board and Committee Membership	Attendance	
Board of Directors	9 of 9	100%
Audit, Finance and Risk Committee	7 of 7	100%
Management Resources and Compensation Committee	4 of 4	100%

Securities Held

Year	Common Shares[2]	DSUs[3]	Total of Common Shares and DSUs	Total Market Value of Common Shares and DSUs[4]	Minimum Required[5]
2006	2,000	4,413	6,413	$ 306,221	$300,000
2005	0	2,973	2,973	$ 101,558	

Options Held: None. Non-employee Directors are not eligible to participate in the Company's stock option plan.

Other Public Board Directorships: Canadian Utilities Limited

RON A. BRENNEMAN
Non-independent[1], Management
Age: 60
Calgary, Alberta, Canada
Director since 2000

Ron Brenneman joined Petro-Canada as President and Chief Executive Officer in January 2000. He leads the Company's Executive Leadership Team. He is responsible for the overall strategic direction of the Company and its sound management and performance. Mr. Brenneman holds a Bachelor of Science and a Master of Science. He is a member of the Board of Directors of the Canadian Council of Chief Executives.

Board and Committee Membership	Attendance	
Board of Directors As a member of management, Mr. Brenneman is not a member of any Committee of the Board, but he is invited to attend all Committee meetings other than *in camera* sessions.	9 of 9	100%

Securities Held

Year	Common Shares[2]	DSUs[3]	Total of Common Shares and DSUs	Total Market Value of Common Shares and DSUs[4]	Minimum Required[5]
2006	81,534	217,580	299,114	$ 14,282,693	$4,860,000
2005	78,793	190,887	269,680	$ 10,196,393	

Options Held: 1,219,000

Other Public Board Directorships:[6] Bank of Nova Scotia and BCE Inc.

1 Independent: refers to the standards of independence established under Section 303A.02 of the NYSE Listed Company Manual, Section 301 and Rule 10A-3 of the *Sarbanes-Oxley Act of 2002* and Section 1.2 of Canadian Securities Administrators' National Instrument 58-101.

2 Common Shares refers to the number of common shares beneficially owned, or over which control or direction is exercised by the Director, as of December 31, 2006 and December 31, 2005, respectively. For Messrs Currie, Kierans and Simpson, 2006 includes 30,000, 9,100 and 2,000 shares, respectively, purchased in January and/or February 2007.

3 DSUs refers to the number of deferred stock units held by the Director as of December 31, 2006 and December 31, 2005, respectively.

4 The Total Market Value of Common Shares is determined by multiplying the number of common shares held by the closing price of the common shares on the TSX on December 29, 2006 (the last trading day prior to December 31, 2006) of $47.75 and on December 31, 2005 of $46.65, as applicable. The Total Market Value of DSUs is based on the previous five-day average market value of Petro-Canada's common shares as of December 29, 2006 of $47.75 and December 31, 2005 of $34.16. Dividend equivalents are credited on a quarterly basis.

5 Each non-employee Director is required to hold a minimum number of Company shares or share equivalents equal in value to $300,000. Directors have five years to reach this level. Mr. Brenneman, as an employee Director, participates in the Company's Officer Share Ownership Program and is required to hold four times his annual base salary. Refer to Executive Compensation on page 16 of the Management Proxy Circular.

6 Ms. Cook-Bennett and Mr. Kierans both serve on the Board of Manulife Financial Corporation and Messrs Currie and Brenneman both serve on the Board of BCE Inc.

7 Mme Saucier was a Director of Nortel Networks Corporation until June 2005, and was subject to a cease trade order issued on May 17, 2004 as a result of Nortel's failure to file financial statements. The cease trade order was cancelled on June 21, 2005.

8 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.

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 when his or her successor is elected or appointed.

The following table shows information concerning officers of the Company.

Name and Municipality of Residence	Served as an Officer Since	Principal Occupation[1]	Employment History Previous Five years
Brian F. MacNeill, Calgary, Alberta	2000	Chairman of the Board of the Company	Prior to 2001, Mr. MacNeill was President and Chief Executive Officer of Enbridge Inc.
Executive Leadership Team			
Ron A. Brenneman, Calgary, Alberta	2000	President and Chief Executive Officer of the Company	Mr. Brenneman has held the position of President and Chief Executive Officer of the Company since 2000.
Peter S. Kallos, London, England	2003	Executive Vice-President, International	Prior to 2003, Mr. Kallos was the Company's 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.
Boris J. Jackman, Mississauga, Ontario	1993	Executive Vice-President, Downstream	Mr. Jackman has held the position of Executive Vice-President, Downstream since 1998.
E.F.H. Roberts, Calgary, Alberta	1989	Executive Vice-President and Chief Financial Officer	Mr. Roberts has held the position of Executive Vice-President and Chief Financial Officer since 2004, and prior thereto was Senior Vice-President and Chief Financial Officer since 2000.
Neil J. Camarta,[2] Calgary, Alberta	2005	Senior Vice-President, Oil Sands	Prior to 2006, Mr. Camarta was the Company's Vice-President, Corporate Planning and Communications, and prior thereto was Senior Vice-President, Oil Sands for Shell Canada Limited.
Kathleen E. Sendall, Calgary, Alberta	1996	Senior Vice-President, North American Natural Gas	Ms. Sendall has held the position of Senior Vice-President, North American Natural Gas since 2000.
William A. Fleming,[3] St. John's, Newfoundland and Labrador	2005	Vice-President, East Coast	Prior to 2005, Mr. Fleming was Terra Nova Asset Manager, and prior thereto was Manager of Engineering and Operations, Western Canada.
Upstream			
Youssef Ghoniem, Dorsten, Germany	2002	Senior Vice-President, Operations	Prior to 2002, Mr. Gohniem was Executive Board Member for Veba Oil & Gas GmbH.
Gordon Carrick, London, England	2002	Senior Vice-President, Operations and Technology	Prior to 2002, Mr. Carrick was Terra Nova Asset Manager.
Nicholas A. Maden, London, England	2003	Vice-President, International and Offshore Exploration	Prior to 2003, Mr. Maden was the Company's 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.
Graham Lyon, London, England	2004	Vice-President, Business Development, International	Prior to 2004, Mr. Lyon was the Company's Senior Director, Business Development, and prior thereto was head of Business Development, Deminex UK Oil & Gas.
Donald M. Clague, Denver, Colorado	2002	Vice-President, U.S. Operations, North American Natural Gas	Prior to 2002, Mr. Clague was Manager, Exploration East Coast/Offshore, and prior thereto was Chief Geophysicist.
Francois Langlois, Calgary, Alberta	2002	Vice-President, Exploration, North American Natural Gas	Prior to 2002, Mr. Langlois was Manager, Southern Exploration, and prior thereto was General Manager, North Africa, and prior thereto was Team Leader, Foothills Exploration.
John D. Miller, Calgary, Alberta	2004	Vice-President, Natural Gas Marketing	Prior to 2004, Mr. Miller 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.
Leon Sorenson, Calgary, Alberta	2004	Vice-President, Canadian Operations, North American Natural Gas	Prior to 2004, Mr. Sorenson 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.

Name and Municipality of Residence	Served as an Officer Since	Principal Occupation[1]	Employment History Previous Five years
Susan M. MacKenzie, Calgary, Alberta	2006	Vice-President, *In Situ* Development and Operations, Oil Sands	Prior to 2006, Ms. MacKenzie was the Company's General Manager, Oil Sands *In Situ*, and prior thereto was Senior Director, Bitumen, and prior thereto was Project Manager, Oil Sands Bitumen.
Colin H. Cook, Calgary, Alberta	2006	Vice-President, Marketing and Development, Oil Sands	Prior to 2006, Mr. Cook was the Company's General Manager, Marketing and Integration, Oil Sands, and prior thereto was General Manager, Business Integration Oil Sands.
Hugh D. MacGregor, Calgary, Alberta	2006	Vice-President, Fort Hills, Oil Sands	Prior to 2006, Mr. MacGregor was the Company's Senior Director, Oil Sands Refinery Conversion Program.
Downstream			
Randall B. Koenig, Oakville, Ontario	1996	Vice-President, Lubricants	Mr. Koenig has held the position of Vice-President, Lubricants since 1998.
Frederick Scharf, Mississauga, Ontario	2003	Vice-President, Wholesale/Retail Sales, Service and Operations	Prior to 2003, Mr. Scharf was General Manager, Western Canada Wholesale/Retail.
Philip Churton, Burlington, Ontario	2005	Vice-President, Marketing	Prior to 2005, Mr. Churton was General Manager, Sales Services & Operations, Central Canada.
Daniel P. Sorochan, Mississauga, Ontario	2003	Vice-President, Refining and Supply	Prior to 2003, Mr. Sorochan was Senior Director of Business Development, Refining and Supply, and prior thereto was General Manager, Oakville refinery.
Shared Services			
Scott R. Miller,[4] Calgary, Alberta	2006	Vice-President, General Counsel	Prior to 2006, Mr. Miller was Associate General Counsel, Upstream. Mr. Miller is an Associate Member of the Executive Leadership Team.
Andrew Stephens, Calgary, Alberta	1993	Vice-President, Human Resources	Mr. Stephens has held the position of Vice-President, Human Resources since 2005, and prior thereto was Vice-President, Corporate Planning and Communications, and prior thereto was Vice-President, Refining and Supply. Mr. Stephens is an Associate Member of the Executive Leadership Team.
M. A. (Greta) Raymond, Calgary, Alberta	2001	Vice-President, Environment, Health, Safety and Security/Corporate Responsibility	Ms. Raymond has held the position of Vice-President, Environment, Safety and Social Responsibility since 2005, and prior thereto was also responsible for Human Resources. Ms. Raymond is an Associate Member of the Executive Leadership Team.
Helen Wesley,[5] London, England	2006	Vice-President, Finance IBU	Prior to 2006, Ms. Wesley was the Company's Senior Director, Corporate Communications, and prior thereto was Manager Planning, and prior to that was with Nova Chemicals as Vice-President, Purchasing and Supply.
Wayne R. Pennington,[6] Calgary, Alberta	2006	Treasurer	Prior to 2006, Mr. Pennington was the Company's Assistant Controller, Corporate, and prior to that was Senior Director, Financial Reporting and Accounting, and prior thereto was with EnCana Corporation as Assistant Controller, and prior to that was with PanCanadian Energy as Manager Financial Reporting and Forecasts.
Hugh L. Hooker, Calgary, Alberta	2004	Chief Compliance Officer, Corporate Secretary, Associate General Counsel	In 2006, Mr. Hooker added Chief Compliance Officer to his responsibilities. Prior to 2004, Mr. Hooker was Associate General Counsel.
Michael Danyluk, Calgary, Alberta	2004	Chief Information Officer	Prior to 2004, Mr. Danyluk was Senior Director of Information Systems.
Michael C. Barkwell, Calgary, Alberta	2005	Controller	Prior to 2005, Mr. Barkwell was Assistant Controller, Downstream, and prior thereto was Director of Financial Reporting.

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 as indicated.
2 Mr. Camarta replaced Brant G. Sangster as Senior Vice-President, Oil Sands. Mr. Sangster retired from the Company in August 2006.
3 Mr. Fleming retired in February 2007.
4 Mr. Miller replaced W.A. (Alf) Peneycad as Vice-President, General Counsel. Mr. Peneycad retired from the Company in June 2006.
5 Ms. Wesley replaced Gerhard Kinast as Vice-President, Finance International. Mr. Kinast retired from the Company in February 2006.
6 Mr. Pennington replaced Douglas S. Fraser as Treasurer. Mr. Fraser left the Company in May 2006.

Share Ownership

As at December 31, 2006, the Directors and officers of Petro-Canada, as a group, beneficially owned or exercised control over 403,926 common shares, or less than 1% of the common shares of the Company outstanding as of such date.

Corporate Governance

Petro-Canada's Board of Directors (the Board) believes that superior corporate governance practices are essential to the Company's success. The Company maintains a best-practices standard in all its corporate governance initiatives and the Corporate Governance and Nominating Committee (the Governance Committee) reviews its corporate governance policies every time it meets.

Governance Committee Responsibilities

The Governance Committee is responsible for overseeing the Company's corporate governance matters and making appropriate recommendations to the Board. In particular, it helps the Board:

- develop and implement corporate governance procedures
- propose nominees for election to the Board
- assess the size, competencies and skills of the Board
- conduct Board, Committee and Director evaluations
- oversee the orientation and education of Board members

2006 Governance Initiatives

This year, the Governance Committee completed a number of governance initiatives, including:

- a gap analysis on Director education to benchmarch Petro-Canada's Director orientation and education programs
- reviewing the Board membership matrix in connection with succession planning
- an assessment of the annual Board review process
- revision of the Corporate Governance Handbook

The Company's management regularly reports to the Governance Committee on governance trends, issues and developments.

Corporate Governance Practices

Petro-Canada is a Canadian integrated oil and gas company with shares listed on the TSX and the NYSE. The Company's corporate governance practices follow the rules and guidelines from both Canadian and U.S. securities regulators, including the following:

Canadian	National Instrument 58-101 (Disclosure of Corporate Governance Practices) National Policy 58-201 (Corporate Governance Guidelines) National Instrument 52-109 (Certification of Disclosure) Multilateral Instrument 52-110 (Audit Committees) (MI 52-110)
U.S.	*Sarbanes-Oxley Act of 2002* (SOX) NYSE Corporate Governance Standards for U.S. domestic issuers (NYSE Standards)[1]

1 Although the NYSE Standards do not apply to Petro-Canada, the Company's corporate governance practices substantially comply with these Standards.

Board Composition and Independence

Petro-Canada's Articles say that the Board must have a minimum of 9 and a maximum of 13 Directors.

Petro-Canada's Board consists of qualified members with backgrounds that help the Company to meet its performance targets. The Board has proposed 11 nominees for election to the Board. Ten are independent; Ron A. Brenneman, Petro-Canada's President and Chief Executive Officer, is the one Director who is not independent under MI 52-110, the NYSE standards and SOX. The Governance Committee annually reviews the size and effectiveness of the Board as a whole, and the skills and contributions of its members. The Company has an annual process to confirm details on Directors' current employers, other directorships, shareholdings and business relationships. This helps in deciding each Director's independence.

This year, the Governance Committee has recommended to the Board the 11 Board nominees as having the appropriate mix of experience and skill to oversee the stewardship of Petro-Canada. Please see Director Biographies in the Management Proxy Circular for more detail.

Board Roles and Responsibilities

The Board supervises the management of Petro-Canada and is responsible for its overall stewardship. In summary, the Board is responsible for:

- management selection, retention, succession and remuneration
- overseeing the development of the Company's business strategy and monitoring its progress
- approving significant Company policies and procedures
- timely and accurate reporting to shareholders and public filing of documents
- approving major Company decisions and documents, including such things as audited financial statements, declaration of dividends, offering circulars and initiation of bylaw amendments

The Board meets at least six times per year and schedules *in camera* sessions at each meeting. In 2006, there were nine Board and *in camera* meetings. The Chair periodically solicits recommendations from Board members on matters that should be brought before the Board. All Directors receive a meeting agenda and background material on agenda items prior to each meeting so that they have the opportunity to review and consider the items that will be discussed. Individual Directors will notify the Board of a material interest in any matter that the Board is considering. The interested Board member is not entitled to participate in Board discussions or vote on the particular matter at the meeting.

The Board Mandate (attached to the Management Proxy Circular as Appendix A) and Terms of Reference for an individual Director contain more detail on the membership, procedures and responsibilities of the Board. These documents can be found in the Corporate Governance Handbook at www.petro-canada.ca.

Board Committees

The Board has five standing Committees:

- Audit, Finance and Risk (Audit Committee)
- Corporate Governance and Nominating (Governance Committee)
- Environment, Health and Safety (EH&S Committee)
- Management Resources and Compensation (Compensation Committee)
- Pension (Pension Committee)

All members of the Committees are independent and *in camera* sessions are scheduled at each Committee meeting. The Governance Committee recommends to the Board the appointees of Committee Chairs. The Chairs of each Committee are responsible for the management, development and effective performance of their Committee. The Chair provides leadership to the Committee, with an aim to fulfilling the Committee's Charter and other matters delegated to it by the Board. The Committee Chairs' mandates are available in the Corporate Governance Handbook at www.petro-canada.ca.

The following summarizes the Committees' responsibilities. Each Committee's Charter contains details of its membership, procedures and responsibilities. The Charters can be found in the Corporate Governance Handbook at www.petro-canada.ca.

Audit Committee
All members of the Audit Committee are independent and financially literate. One member is recognized as a "financial expert" in accordance with SOX requirements. *In camera* sessions are held at each Audit Committee meeting, of which there were seven in 2006.

The Audit Committee helps the Board with (i) all matters relating to the external and contract internal auditors, (ii) reviewing and approving the audited financial statements, (iii) reviewing litigation claims, reserves data and related disclosures and (iv) overseeing accounting and risk management policies, reporting practices and internal controls.

Governance Committee
The Governance Committee helps the Board with (i) developing and complying with corporate governance policies and procedures, (ii) recommending candidates for election to the Board and its Committees, (iii) assessing the management, development and effective performance of the Board, its Committees, and their respective Mandates and Charters and (iv) orientation, education and development of Board members. In 2006, there were four Committee and *in camera* meetings.

EH&S Committee
All members of the EH&S Committee are independent and *in camera* sessions are held at each meeting. In 2006, there were three Committee and *in camera* meetings. The EH&S Committee helps the Board with (i) setting strategies, goals, policies and procedures in connection with environment, health and safety matters, (ii) monitoring Petro-Canada's performance in relation to these matters and (iii) complying with environment, health and safety legislation, other related regulatory provisions and public policy.

Compensation Committee
All members of the Compensation Committee are independent and *in camera* sessions are held at each meeting. In 2006, there were four Committee and *in camera* meetings. The Compensation Committee helps the Board with setting the compensation for the President and Chief Executive Officer and other senior officers, as well as overseeing the plans for (i) compensation, development and retention of employees, (ii) succession planning for senior officers and (iii) general compensation and human resource policies and issues.

Pension Committee
All members of the Pension Committee are independent and *in camera* sessions are held at each meeting. In 2006, there were two Committee and *in camera* meetings. The Pension Committee helps the Board with (i) setting strategies, goals, policies and procedures for the Company's pension plan, (ii) effectively governing the pension plan and (iii) monitoring the pension plan's financial position, and its compliance with legislative, regulatory and internal policy requirements.

Position Descriptions

Chair of the Board
The Chair of the Board is an independent Director whose position is separate from the President and Chief Executive Officer. The Chair leads the Board and is responsible for enhancing its effectiveness. The Chair also acts as an advisor to the President and Chief Executive Officer and to other officers in all matters concerning the management of Petro-Canada. The Governance Committee annually reviews the performance of the Chair of the Board.

President and Chief Executive Officer
The President and Chief Executive Officer leads Petro-Canada's Executive Leadership Team. He is responsible for the strategic direction of the Company and its sound management and performance. Each January, the Chair of the Board and the Chair of the Governance Committee canvas the Board members for their input on the President and Chief Executive Officer's performance, request input and comments from other officers as they may see fit and have a detailed discussion with the President and Chief Executive Officer. The Chair of the Board provides an evaluation report to the Management Resources and Compensation Committee, which recommends to the Board the compensation of the President and Chief Executive Officer for the upcoming year.

Detailed position descriptions for the Chair of the Board, Chief Executive Officer and Corporate Secretary are published in the Corporate Governance Handbook available at www.petro-canada.ca.

Director Evaluation and Compensation

The Governance Committee annually reviews the size, composition, charters and membership of the Board and each Board Committee, evaluating the effectiveness of the Board, its Committees and the contribution of individual Board members. The Board receives an annual report of the Governance Committee's findings. The Governance Committee also reviews Directors' compensation and recommends Director remuneration of the Board. The main objective is to have the compensation realistically reflect the responsibilities and risk involved in being a Director.

Director Orientation and Continuing Education

We give each new Director copies of:

- business plan and implementation strategy
- annual disclosure documents
- minutes of the Board and Committee meetings for the past year
- Corporate Governance Handbook
- Code of Business Conduct

Each new Director has one-on-one sessions with each of the business unit leaders. As required, we arrange a mentor for every new Director to help them learn about the Company's operations.

Petro-Canada encourages all Directors to take advantage of continuing education programs. The Company supports Directors through a cost-sharing arrangement or by paying all reasonable expenses. Petro-Canada also provides a number of in-house education sessions, such as tours of the Company's facilities and technical paper presentations.

Ethical Business Conduct

Code of Business Conduct - All Board members, employees and contractors must follow Petro-Canada's Code of Business Conduct (the Code), which is available on the Company's website (www.petro-canada.ca). The Code provides guidance on such things as ethical business conduct generally, conflicts of interest, dealing with confidential information, insider information and the Policy for the Prevention of Improper Payments. The Board has not granted any waiver of the Code; therefore, no material change report has been filed in this regard.

Annual certificates are provided by Petro-Canada's executive officers verifying that (i) they adhere to the Code, (ii) the Code is regularly communicated and (iii) their employees adhere to the Code. Employees take electronic training on the Code's content and certify their compliance every two years. All new employees must certify that they will comply with the Code during their employment.

Senior Financial Officers - Petro-Canada's senior financial officers provide annual certifications under the Company's Code of Ethics for Financial Officers. The President and Chief Executive Officer, and Executive Vice-President and Chief Financial Officer certify the Company's quarterly and annual financial statements for filing with the Canadian and U.S. securities regulators.

Whistleblower Hotline - With the Company's whistleblower hotline, employees can report questionable accounting or auditing matters on an anonymous and confidential basis. The Chief Compliance Officer oversees the whistleblower hotline and reports complaints received through the hotline to the Chair of the Audit Committee.

Disclosure Policy - Petro-Canada has adopted a Public Disclosure Policy to govern the dissemination of information to the public and further its aim of providing clear and complete disclosure in a timely manner, while complying with all securities regulations. The procedure operating under this Policy establishes a committee that is lead by the Executive Vice-President and Chief Financial Officer, and the Vice-President and General Counsel, with representatives from all business and Shared Services units of the Company. Different types of disclosure are approved by all or part of the committee, as the circumstances warrant. The Chief Financial Officer must approve all material financial disclosures.

This report is submitted by the Corporate Governance and Nominating Committee:

Guylaine Saucier (Chair)
Thomas E. Kierans
Maureen McCaw
Brian MacNeill (*ex-officio* member)

Audit Committee Disclosure

The following reviews certain information regarding the Company's Audit, Finance and Risk Committee, as required pursuant to Multilateral Instrument 52-110.

Audit, Finance and Risk Committee

Chair: Paul D. Melnuk (Designated Financial Expert)
Members: Angus A. Bruneau, Gail Cook-Bennett, Paul Haseldonckx, James W. Simpson
2006 Committee Meetings: Seven

This Committee is composed entirely of independent Directors, each of whom is very knowledgeable in financial matters and is financially literate within the meaning of Multilateral Instrument 52-110. 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, starting on page 69. 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 auditor and external auditor at least once per year. The Committee is responsible for recommending the appointment and compensation of the external auditor. 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 website 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, 2006 as follows: (a) audit fees - $4,024,750 (2005 - $3,217,000), (b) audit related services for pension plan and attest services - $196,180 (2005 - $213,000), (c) tax advisory fees - nil (2005 - nil), and (d) all other fees - nil (2005 - nil).

The Board of Directors adheres to a practice of limiting the auditors from providing services not related to the audit. All services provided by the auditors are pre-approved by the Audit, Finance and Risk Committee.

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.

TRANSFER AGENTS AND REGISTRARS

In Canada:
CIBC Mellon Trust Company
600, 333 - 7 Avenue S.W.
Calgary, Alberta T2P 2Z1
Telephone: 1-800-387-0825 or
416-643-5000 outside of North America
Website: www.cibcmellon.com

In the U.S.:
Mellon Investor Services LLC
Telephone: 1-800-387-0825
Website: www.cibcmellon.com

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.

INTERESTS OF EXPERTS

Deloitte & Touche LLP is the auditor of the Company and is independent in accordance with the Rules of Professional Conduct as outlined by the Institute of Chartered Accountants of Alberta. Deloitte & Touche LLP has prepared an opinion with respect to the Company's Consolidated Financial Statements as at and for the fiscal year ended December 31, 2006, as well as an opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an opinion on the effectiveness of the Company's internal control over financial reporting. Kathleen E. 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. Ms. Sendall does not hold more than 1% of the Company's outstanding securities.

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 1, 2007.

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, 2006 may be obtained from the Company's website at www.petro-canada.ca or by mail upon request from the corporate secretary, 150 - 6 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, 2006. The reserves data consist of the following:
   (i) proved oil and gas reserves and oil sands mining quantities estimated as at December 31, 2006, using constant prices and costs; and
   (ii) the Standardized Measure of Discounted Future Net Cash Flows relating to proved oil and gas reserves and oil sands mining 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 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 reserves and oil sands mining 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, 2006:

STANDARDIZED MEASURE OF FUTURE NET CASH FLOWS
PROVED OIL AND GAS RESERVES AND OIL SANDS MINING
(10% discount rate)
As at December 31, 2006

Location of Reserves (by business)		Standardized Measure (After Deducting Income Taxes)
North American Natural Gas	$	3,493
East Coast Oil		3,233
Northwest Europe		2,090
North Africa/Near East		590
Northern Latin America		148
Syncrude Oil Sands Mining Operation	$	3,539

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 has, 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 22, 2007

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 and oil sands mining quantities estimated as at December 31, 2006, using constant prices and costs; and

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

Petro-Canada's 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). Petro-Canada's qualified internal reserves evaluation staff and management have evaluated the Company's 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 reserves evaluators or auditors as part of its corporate governance practices. In 2006, the independent evaluators/auditors, evaluated/audited approximately 45% of the Company's proved oil and gas reserves data by volume. If the Syncrude oil sands mining proved reserves are included, the percentage of total Company reserves audited was 33%. Their involvement helps assure that our internal reserves data are materially correct.

In the Company's view, the reliability of the internally generated reserves data is not materially less than would be afforded by Petro-Canada involving independent qualified reserves evaluators or independent qualified reserves auditors to evaluate, audit and/or review the reserves data. Petro-Canada's reserves data are international in nature. The Company's securities regulatory reporting is as an SEC registrant and, therefore, Petro-Canada's reserves data are 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. Petro-Canada's procedures, records and controls relating to the accumulation of source data and preparation of reserves data by the Company's internal reserves evaluation staff have been established, refined and documented over many years. Petro-Canada's internal reserves evaluation staff and management include 69 persons, with an average of more than 11 years of relevant experience in evaluating reserves, of whom 44 are qualified reserves evaluators for purposes of Canadian securities regulatory requirements. The Company's internal reserves evaluation management personnel includes 12 persons, with an average of 23 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 22, 2007

SCHEDULE C
AUDIT, FINANCE AND RISK COMMITTEE

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

(i) 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;

(ii) maintain direct lines of communications with the Chief Financial Officer and with the contract auditor and the external auditors;

(iii) monitor the scope and costs of the activity of the contract and external auditors, and assess their performance;

(iv) 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;

(v) 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;

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

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

(viii) 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;

(ix) review all financial information included in annual information forms, prospectuses, other offering memoranda or other documents requiring approval by the Board of Directors;

(x) review the Statement of Management's Responsibility for the 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;

(xi) review the Report of Management on Oil and Gas Disclosure as signed by senior management and directors and included in any published document;

(xii) 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, monitor disclosure thereof in documents reviewed by the Committee;

(xiii) review 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;

(xiv) 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;

(xv) 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;

(xvi) 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 CICA and AICPA professional standards, and other regulatory bodies' requirements, the outsourcing contract and recommendations of management and the contract auditor;

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

(xviii) oversee management's responsibility for designing, installing and maintaining an effective control environment; approve in advance any internal control-related services performed by the external auditor; and receive regular reports on the Company's internal control policies and procedures with particular emphasis on accounting and financial controls, and recommend changes where appropriate;

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

(xx) annually; (a) review the Company's internal procedures for providing reserves information to its reserves evaluators; (b) meet with internal and external reserves evaluators to determine their independence and effectiveness in preparing the reserves data of the Company; (c) review the reserves data included in the annual disclosure made by the Company; and (d) review the Company's internal procedures for assembling and reporting other information associated with oil and gas activities and included in the annual disclosure made by the Company;

(xxi) 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;

(xxii) review and make recommendations to the Board concerning the following:

1) the Company's policies regarding hedging, investments, credit and risk management; and
2) the Company's risk identification, analysis and management procedures;

(xxiii) review, prior to each annual shareholders' meeting, the policies and practices concerning the regular examination of officers expenses and perquisites, including the use of Company assets;

(xxiv) report annually to the full Board, on the state of completion of the Audit, Finance and Risk Committee Annual Agenda Items, with appropriate recommendations; and

(xxv) report annually to the full Board on the Committee's review of the Company's reserves procedures and disclosure and recommend to the Board the approval of the reserves data and other information associated with the Company's oil and gas activities and included in the annual disclosure made by the Company.

2. ORGANIZATION AND PROCEDURES

(i) 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.

(ii) 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.

(iii) 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.

(iv) The external auditor and the contract auditor shall ultimately report to the Board 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.

(v) 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.

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

(vii) The Committee will establish procedures for:

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

2) 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.

The Committee will periodically review its own Terms of Reference, and make recommendations to the Board as required.

CONTROLS AND PROCEDURES

The company has performed an evaluation of its disclosure controls and procedures (as defined by Exchange Act rule 13a-15(e)), as of December 31, 2006. Based on this evaluation, the company's Chief Executive Officer and Chief Financial Officer have concluded that the disclosure controls and procedures are effective in providing reasonable assurances that material information required to be in this annual report is made known to them by others on a timely basis.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

[See page 1 of the Management's Discussion and Analysis Exhibit forming part of this report]

ATTESTATION REPORT OF THE REGISTERED PUBLIC ACCOUNTING FIRM

[See pages 3 and 4 of the Management's Discussion and Analysis Exhibit forming part of this report]

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

The company has not made any changes in internal control over financial reporting that occurred during the period covered by this annual report that has materially affected, or is reasonably likely to materially affect, the company's internal control over financial reporting.

IDENTIFICATION OF THE AUDIT COMMITTEE

Petro-Canada has a separately-designed standing Audit, Finance and Risk Committee. The members of the Audit, Finance and Risk Committee are:

Chair:	P. D. Melnuk
Members:	A. A. Bruneau
	G. Cook-Bennett
	P. Haseldonckx
	J. W. Simpson

AUDIT COMMITTEE FINANCIAL EXPERT

Petro-Canada's Board of Directors has determined that Petro-Canada has an "audit committee financial expert" as defined by regulations of the U.S. Securities and Exchange Commission. The audit committee financial expert is Paul D. Melnuk, Chairman of the Audit, Finance and Risk Committee. Mr. Melnuk has been determined to be "independent", as that term is defined by the New York Stock Exchange's listing standards applicable to Petro-Canada.

CODE OF ETHICS

The company has adopted a code of ethics applicable to its Chief Executive Officer, Chief Financial Officer, principal accounting officer and Controller. A copy of the company's code of ethics and, if applicable, any future amendments or waivers of the code of ethics can be found at the company's website located at www.petro-canada.ca.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

Deloitte & Touche LLP billed the company for services rendered in the year ended December 31, 2006 as follows:

(a) **audit fees** - $4,024,750
(b) **audit related fees** - fees for audit of pension plans and attest services - $196,180
(c) **tax fees** - nil
(d) **all other fees** -- nil

Deloitte & Touche LLP billed the company for services rendered in the year ended December 31, 2005 as follows:

(a) **audit fees** - $3,217,000
(b) **audit related fees** - audits of pension plans and attest services - $213,000
(c) **tax fees** - nil
(d) **all other fees** -- nil

AUDIT COMMITTEE PRE-APPROVAL POLICIES AND PROCEDURES: The Audit, Finance and Risk Committee of Petro-Canada's Board of Directors approves in advance any audit or non-audit service proposed to be provided by Deloitte & Touche LLP for Petro-Canada or its subsidiaries. The Committee has delegated to the Chairman of the Committee full authority to approve any such request, as long as the Chairman presents any such approval to the Committee at its next scheduled meeting. No services were approved pursuant to a waiver within the meaning of Rule 2-01(c) (7)(i)(C) of Regulation S-X in the years ended December 31, 2005 and December 31, 2006.

OFF-BALANCE SHEET ARRANGEMENTS

See page 17 of the Management's Discussion and Analysis Exhibit forming part of this report

CONTRACTUAL OBLIGATIONS

See page17 of the Management's Discussion and Analysis Exhibit forming part of this report

UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

A. Undertaking

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

B. Consent to Service of Process

The Registrant has previously filed a Form F-X with the SEC on March 10, 1994.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereto duly authorized.

PETRO-CANADA

Date: March 29, 2007

/s/ Hugh L. Hooker
Name: Hugh L. Hooker
Title: Chief Compliance Officer, Corporate Secretary, Associate General Counsel

EXHIBITS

Exhibits	Description
99.1	Petro-Canada Consolidated Financial Statements for the year ended December 31, 2006
99.2	Petro-Canada Management's Discussion and Analysis
99.3	Certification of the CEO pursuant to Section 302 of the Sarbanes-Oxley Act
99.4	Certification of the CFO pursuant to Section 302 of the Sarbanes-Oxley Act
99.5	Certification of CEO pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.6	Certification of CFO pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.7	Consent of Deloitte & Touche LLP, Independent Registered Chartered Accountants

Exhibit 99.1

Management, Audit, Finance and Risk Committee, and Auditor Reports

MANAGEMENT'S RESPONSIBILITY FOR THE FINANCIAL STATEMENTS AND REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The preparation and presentation of the Company's Consolidated Financial Statements and the overall quality of the Company's financial reporting are the responsibility of management. The financial statements have been prepared in accordance with Canadian generally accepted accounting principles (GAAP) and necessarily include estimates, which are based on management's best judgments. Information contained elsewhere in the Annual Report is consistent, where applicable, with that contained in the financial statements.

Management is also responsible for establishing and maintaining a system of internal controls over financial reporting to provide reasonable assurance that assets are safeguarded and that reliable financial information is produced for preparation of financial statements. Management conducted an evaluation of the effectiveness of the system of internal control over financial reporting based on the framework in "Internal Control - Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's system of internal control over financial reporting was effective as at December 31, 2006.

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

Management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2006 has been audited by Deloitte & Touche LLP, the Company's Independent Registered Chartered Accountants, who also audited the Company's Consolidated Financial Statements for the year ended December 31, 2006. The Report of Independent Registered Chartered Accountants expresses an unqualified opinion on management's assessment of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting as of December 31, 2006.

The Board of Directors is responsible for overseeing management's performance of its responsibilities for financial reporting and internal control. The Board of Directors exercises this responsibility with the assistance of the Audit, Finance and Risk Committee of the Board of Directors.

Ron A. Brenneman
President and Chief Executive Officer
February 12, 2007

E.F.H. Roberts
Executive Vice-President and Chief Financial Officer
February 12, 2007

AUDIT, FINANCE AND RISK COMMITTEE OF THE BOARD OF DIRECTORS

The Audit, Finance and Risk Committee (the Committee), which is composed of not fewer than three (currently five) independent directors, assists the Board of Directors in the discharge of its responsibility for overseeing management's performance of the financial reporting and internal control responsibilities. The Committee reviews the annual and quarterly Consolidated Financial Statements, accounting policies and the overall quality of the Company's financial reporting, and the financial information contained in prospectuses and in reports filed with regulatory authorities, as required. The Committee also reviews and makes recommendations to the Board of Directors regarding financial matters and oversees the process that management has in place to identify business risks. The Committee members are all independent pursuant to National Instrument 52-110 (N1 52-110), NYSE Corporate Governance Standards and the Sarbanes-Oxley Act of 2002 (SOX), and are financially literate, with one member who has been recognized as a "financial expert" in accordance with SOX requirements.

With respect to the external auditors, the Committee reviews and approves the terms of engagement, the scope and plan for the external audit, and reviews the results of the audit and the Reports of the Independent Registered Chartered Accountants. The external auditors report to the Committee. The Committee discusses the external auditors' independence from management and the Company with the auditors and receives written confirmation of their independence. The Committee also recommends to the Board of Directors the external auditors to be appointed by the shareholders and approves in advance fees for the external auditors' services.

With respect to the contract auditor's engagement to provide internal audit services, the Committee reviews the engagement contract, reviews and approves the scope and plan for the internal audit, receives periodic reports and reviews significant findings and recommendations. The contract auditor reports to the Committee.

Senior management, the external auditors and the contract auditor attend all Audit, Finance and Risk Committee meetings and each is provided with the opportunity to meet privately with the Committee.

Paul D. Melnuk
Chairman of the Audit, Finance and Risk Committee
February 12, 2007

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors and Shareholders of Petro-Canada:

We have audited management's assessment, included in the accompanying Management's Responsibility for the Financial Statements and Report on Internal Control Over Financial Reporting, that Petro-Canada and subsidiaries (the Company) maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in "Internal Control − Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

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

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

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2006 is fairly stated, in all material respects, based on the criteria established in "Internal Control − Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the criteria established in "Internal Control − Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the Consolidated Financial Statements as of and for the year ended December 31, 2006 of the Company and our report dated February 12, 2007 expressed an unqualified opinion on those financial statements and included a separate report titled Comments by Independent Registered Chartered Accountants on Canada-United States of America Reporting Difference referring to a change in accounting principle.

Deloitte & Touche LLP

Independent Registered Chartered Accountants
Calgary, Canada
February 12, 2007

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors and Shareholders of Petro-Canada:

We have audited the accompanying Consolidated Balance Sheet of Petro-Canada and subsidiaries as of December 31, 2006 and 2005, and the related Consolidated Statements of Earnings, Retained Earnings and Cash Flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

With respect to the financial statements for the year ended December 31, 2006, we conducted our audit in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). With respect to the financial statements for the years ended December 31, 2005 and December 31, 2004, we conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such Consolidated Financial Statements present fairly, in all material respects, the financial position of Petro-Canada and subsidiaries as of December 31, 2006 and 2005 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 in conformity with Canadian generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2006, based on the criteria established in "Internal Control − Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 12, 2007 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Deloitte & Touche LLP

Independent Registered Chartered Accountants
Calgary, Canada
February 12, 2007

COMMENTS BY INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS ON CANADA-UNITED STATES OF AMERICA REPORTING DIFFERENCE

The standards of the Public Company Accounting Oversight Board (United States) require the addition of an explanatory paragraph when there are changes in accounting principles that have a material effect on the comparability of the Company's financial statements, such as the changes described in Note 2 to the Consolidated Financial Statements. Although we conducted our audits in accordance with both Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), our report to the Board of Directors and shareholders on the Consolidated Financial Statements of Petro-Canada, dated February 12, 2007, is expressed in accordance with Canadian reporting standards, which do not require a reference to such changes in accounting principles in the auditors' report when the change is properly accounted for and adequately disclosed in the financial statements.

Deloitte & Touche LLP

Independent Registered Chartered Accountants
Calgary, Canada
February 12, 2007

CONSOLIDATED STATEMENT OF EARNINGS

(stated in millions of Canadian dollars, except per share amounts)

For the years ended December 31,		**2006**		2005		2004
REVENUE						
Operating	**$**	**18,911**	$	17,585	$	14,270
Investment and other income (expense) *(Note 5)*		**(242)**		(806)		(312)
		18,669		16,779		13,958
EXPENSES						
Crude oil and product purchases		**9,649**		8,846		6,740
Operating, marketing and general *(Note 6)*		**3,180**		2,962		2,572
Exploration *(Note 15)*		**339**		271		235
Depreciation, depletion and amortization *(Notes 6 and 15)*		**1,365**		1,222		1,256
Unrealized gain on translation of foreign currency denominated long-term debt		**(1)**		(88)		(77)
Interest		**165**		164		142
		14,697		13,377		10,868
EARNINGS FROM CONTINUING OPERATIONS BEFORE INCOME TAXES		**3,972**		3,402		3,090
PROVISION FOR INCOME TAXES *(Note 7)*						
Current		**2,073**		1,794		1,365
Future		**311**		(85)		27
		2,384		1,709		1,392
NET EARNINGS FROM CONTINUING OPERATIONS		**1,588**		1,693		1,698
NET EARNINGS FROM DISCONTINUED OPERATIONS *(Note 4)*		**152**		98		59
NET EARNINGS	**$**	**1,740**	$	1,791	$	1,757
EARNINGS PER SHARE FROM CONTINUING OPERATIONS *(Note 8)*						
Basic	**$**	**3.15**	$	3.27	$	3.21
Diluted	**$**	**3.11**	$	3.22	$	3.17
EARNINGS PER SHARE *(Note 8)*						
Basic	**$**	**3.45**	$	3.45	$	3.32
Diluted	**$**	**3.41**	$	3.41	$	3.28

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

(stated in millions of Canadian dollars)

For the years ended December 31,		**2006**		2005		2004
RETAINED EARNINGS AT BEGINNING OF YEAR	**$**	**7,018**	$	5,408	$	3,810
Net earnings		**1,740**		1,791		1,757
Dividends on common shares		**(201)**		(181)		(159)
RETAINED EARNINGS AT END OF YEAR	**$**	**8,557**	$	7,018	$	5,408

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENT OF CASH FLOWS

(stated in millions of Canadian dollars)

For the years ended December 31,	**2006**	2005	2004
OPERATING ACTIVITIES			
Net earnings	**$ 1,740**	$ 1,791	$ 1,757
Less: Net earnings from discontinued operations	**152**	98	59
Net earnings from continuing operations	**1,588**	1,693	1,698
Items not affecting cash flow from continuing operating activities:			
Depreciation, depletion and amortization	**1,365**	1,222	1,256
Future income taxes	**311**	(85)	27
Accretion of asset retirement obligations *(Note 20)*	**54**	50	50
Unrealized gain on translation of foreign currency denominated long-term debt	**(1)**	(88)	(77)
Gain on disposal of assets *(Note 5)*	**(30)**	(48)	(12)
Unrealized loss associated with the Buzzard derivative contracts *(Note 24)*	**259**	889	333
Other	**18**	14	33
Exploration expenses *(Note 15)*	**123**	140	117
Proceeds from sale of accounts receivable *(Note 10)*	**-**	80	399
(Increase) decrease in non-cash working capital related to continuing operating activities *(Note 9)*	**(79)**	(84)	104
Cash flow from continuing operating activities	**3,608**	3,783	3,928
Cash flow from discontinued operating activities *(Note 4)*	**15**	204	233
Cash flow from operating activities	**3,623**	3,987	4,161
INVESTING ACTIVITIES			
Expenditures on property, plant and equipment and exploration *(Note 15)*	**(3,435)**	(3,606)	(3,955)
Proceeds from sale of assets *(Note 4)*	**688**	81	44
Increase in deferred charges and other assets	**(50)**	(70)	(36)
Acquisition of Prima Energy Corporation *(Note 12)*	**-**	-	(644)
Decrease in non-cash working capital related to investing activities *(Note 9)*	**59**	237	10
Cash flow used in investing activities	**(2,738)**	(3,358)	(4,581)
FINANCING ACTIVITIES			
Increase (decrease) in short-term notes payable	**-**	(303)	314
Proceeds from issue of long-term debt *(Note 18)*	**-**	762	533
Repayment of long-term debt	**(7)**	(6)	(299)
Proceeds from issue of common shares *(Note 21)*	**44**	64	39
Purchase of common shares *(Note 21)*	**(1,011)**	(346)	(447)
Dividends on common shares	**(201)**	(181)	(159)
Increase in non-cash working capital related to financing activities *(Note 9)*	**-**	-	(26)
Cash flow used in financing activities	**(1,175)**	(10)	(45)
(DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS	**(290)**	619	(465)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	**789**	170	635
CASH AND CASH EQUIVALENTS AT END OF YEAR *(Note 13)*	**$ 499**	$ 789	$ 170
CASH AND CASH EQUIVALENTS - DISCONTINUED OPERATIONS *(Note 4)*	**$ -**	$ 68	$ 206
CASH AND CASH EQUIVALENTS - CONTINUING OPERATIONS	**$ 499**	$ 721	$ (36)

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED BALANCE SHEET

(stated in millions of Canadian dollars)

As at December 31,		**2006**		2005
ASSETS				
CURRENT ASSETS				
Cash and cash equivalents *(Note 13)*	**$**	**499**	$	721
Accounts receivable *(Note 10)*		**1,600**		1,617
Inventories *(Note 14)*		**632**		596
Future income taxes *(Note 7)*		**95**		-
Assets of discontinued operations *(Note 4)*		**-**		237
		2,826		3,171
PROPERTY, PLANT AND EQUIPMENT, NET *(Note 15)*		**18,577**		15,921
GOODWILL *(Note 16)*		**801**		737
DEFERRED CHARGES AND OTHER ASSETS *(Note 17)*		**442**		415
ASSETS OF DISCONTINUED OPERATIONS *(Note 4)*		**-**		411
	$	**22,646**	$	20,655
LIABILITIES AND SHAREHOLDERS' EQUITY				
CURRENT LIABILITIES				
Accounts payable and accrued liabilities	**$**	**3,319**	$	2,895
Income taxes payable		**22**		82
Liabilities of discontinued operations *(Note 4)*		**-**		102
Current portion of long-term debt		**7**		7
		3,348		3,086
LONG-TERM DEBT *(Note 18)*		**2,887**		2,906
OTHER LIABILITIES *(Note 19)*		**1,826**		1,888
ASSET RETIREMENT OBLIGATIONS *(Note 20)*		**1,170**		882
FUTURE INCOME TAXES *(Note 7)*		**2,974**		2,405
COMMITMENTS AND CONTINGENT LIABILITIES *(Note 25)*				
SHAREHOLDERS' EQUITY				
Common shares *(Note 21)*		**1,366**		1,362
Contributed surplus *(Note 21)*		**469**		1,422
Retained earnings		**8,557**		7,018
Foreign currency translation adjustment		**49**		(314)
		10,441		9,488
	$	**22,646**	$	20,655

See accompanying Notes to Consolidated Financial Statements

Approved on behalf of the Board of Directors

Ron A. Brenneman
Director

Brian F. MacNeill
Director

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(stated in millions of Canadian dollars, unless otherwise stated)

Note 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Basis of Presentation

The Consolidated Financial Statements include the accounts of Petro-Canada and all subsidiary companies (the Company) and are prepared in accordance with Canadian generally accepted accounting principles (GAAP). Differences between Canadian and United States GAAP are explained in Note 27.

Substantially all of the Company's exploration and development activities are conducted jointly with others. Only the Company's proportionate interests in such activities are reflected in the Consolidated Financial Statements.

The preparation of the Consolidated Financial Statements requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and the disclosure of contingencies. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur. Significant estimates used in the preparation of the financial statements include, but are not limited to, asset retirement obligations, income taxes, employee future benefits, the estimates of oil and gas reserves and related depreciation, depletion and amortization, the valuation of the Buzzard derivative contracts and the valuation of goodwill.

(b) Revenue Recognition

Revenue from the sale of crude oil, natural gas, natural gas liquids, purchased products and refined petroleum products is recorded when title passes to the customer. Revenue represents the Company's share and is recorded net of royalty payments to governments and other mineral interest owners. Inter-segment sales are accounted for at market values and included, for segmented reporting, in revenues of the segment making the transfer and expenses of the segment receiving the transfer; these amounts are eliminated on consolidation.

International operations conducted pursuant to exploration and production-sharing agreements (EPSAs) are reflected in the Consolidated Financial Statements based on the Company's working interest in such operations. Under the EPSAs, the Company and other non-governmental partners pay all operating and capital costs for exploring and developing the concessions. Each EPSA establishes specific terms for the Company to recover these costs (Cost Recovery Oil) and to share in the production profits (Profit Oil). Cost Recovery Oil is determined in accordance with a formula that is generally limited to a specified percentage of production during each fiscal year. Profit Oil is that portion of production remaining after deducting Cost Recovery Oil and is shared between the joint venture partners and the government of each country, varying with the level of production. Cost Recovery Oil and Profit Oil are reported as sales revenue. Profit Oil that is attributable to the government includes an amount in respect of all deemed income taxes payable by the Company under the laws of the respective country. All other government stakes, other than income taxes, are considered to be royalty interests.

(c) Transportation Costs

Transportation costs incurred to transport crude oil, natural gas and refined products to customers, which are included in operating marketing and general expenses, are recognized when the product is delivered and the service is provided.

Note 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES *continued*

(d) Foreign Currency Translation

Monetary assets and liabilities are translated into Canadian dollars at rates of exchange in effect at the balance sheet date. With the exception of items pertaining to self-sustaining operations, the other assets and related depreciation, depletion and amortization, other liabilities, revenue and other expense items are translated into Canadian dollars at rates of exchange in effect at the respective transaction dates. The resulting exchange gains or losses are included in earnings.

The Company's International business segment and the U.S. Rockies upstream operations included in the North American Natural Gas business segment are operated on a self-sustaining basis. Assets and liabilities of these operations, including associated long-term debt, are translated into Canadian dollars at period end exchange rates, while revenues and expenses are converted using average rates for the period. Gains and losses from the translation into Canadian dollars are deferred and included in the foreign currency translation adjustment as part of shareholders' equity.

(e) Income Taxes

The Company follows the liability method of accounting for income taxes. Under this method, future income taxes are recognized, using substantively enacted income tax rates, based on the temporary differences between the carrying amounts of assets and liabilities reported in the financial statements and their respective tax bases. The effect of a change in income tax rates on future income tax assets and liabilities is recognized in income in the period the change occurs.

(f) Earnings Per Share

Basic earnings per share are calculated by dividing the net earnings available to common shareholders by the weighted-average number of common shares outstanding. Diluted earnings per share reflect the potential dilution that would occur if stock options, excluding stock options with a cash payment alternative, were exercised. The treasury stock method is used in calculating diluted earnings per share, which assumes that any proceeds received from the exercise of in-the-money stock options would be used to purchase common shares at the average market price for the period. A liability expense is recorded for stock options with a cash payment alternative. Accordingly, the potential common shares associated with these stock options are not included in the calculation of diluted earnings per share.

(g) Cash and Cash Equivalents

Cash and cash equivalents comprise cash in banks, less outstanding cheques, and short-term investments with a maturity of 90 days or less when purchased. Short-term investments are recorded at the lower of cost or market value.

(h) Sale of Accounts Receivable

The transfers of accounts receivable are accounted for as sales, other than the retained interest, when the Company has surrendered control over the transferred receivables and received proceeds. Gains or losses are recognized as other income or expenses and are dependent upon the purchase discount as well as the previous carrying amount of the receivables transferred, which is allocated between the receivables sold and the retained interest, based on their relative fair values at the date of the transfer. Fair value is determined based on the present value of future expected cash flows.

Note 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES *continued*

(i) Inventories

Inventories are stated at the lower of cost and net realizable value. Cost of crude oil and refined products is determined primarily on a "last-in, first-out" (LIFO) basis. Cost of other inventory is determined primarily on an average cost basis. Costs include direct and indirect expenditures incurred in bringing an item or product to its existing condition and location.

(j) Investments

Investments in companies over which the Company has significant influence are accounted for using the equity method. Other long-term investments are accounted for using the cost method.

(k) Property, Plant and Equipment

Investments in exploration and development activities are accounted for using the successful efforts method. Under this method, the acquisition cost of unproved acreage is capitalized. Costs of exploratory wells are initially capitalized pending determination of proved reserves. Costs of wells which are assigned proved reserves remain capitalized, while costs of unsuccessful wells are charged to earnings. All other exploration costs, including geological and geophysical costs, are charged to earnings as incurred. Development costs, including the cost of all wells, are capitalized.

Maintenance and repair costs, including planned major maintenance, are expensed as incurred.

The interest cost of debt attributable to the construction of major new facilities is capitalized during the construction period.

Producing properties and significant unproved properties are assessed annually, or as economic events dictate, for potential impairment. Impairment is assessed by comparing the estimated net undiscounted future cash flows to the carrying value of the asset. If required, the impairment recorded is the amount by which the carrying value of the asset exceeds its fair value.

(l) Depreciation, Depletion and Amortization

Depreciation and depletion of capitalized costs of oil and gas producing properties are calculated using the unit of production method. Development and exploration drilling and equipment costs are depleted over the remaining proved developed reserves and proved property acquisition costs over the remaining proved reserves.

Depreciation of other plant and equipment is provided on either the unit of production method or the straight line method, as appropriate. Straight line depreciation is based on the estimated service lives of the related assets, which range from three to 25 years.

Deferred financing costs are amortized on a straight line basis over the term of the related liability.

Costs associated with significant development projects are not depleted until commencement of commercial production.

Note 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES *continued*

(m) Asset Retirement Obligations

The fair values of estimated asset retirement obligations are recorded as liabilities when incurred and the associated cost is capitalized as part of the cost of the related asset. Over time, the liabilities are accreted for the change in their present value and the initial capitalized costs are depreciated over the useful lives of the related assets. The associated accretion is recorded in operating expense and the depreciation is included in depreciation, depletion and amortization expense. Actual expenditures incurred are charged against the accumulated obligation.

(n) Goodwill

Acquisitions are accounted for using the purchase method. Under this method, identifiable assets and liabilities are recorded at fair value as of the date of acquisition. Goodwill, which is not amortized, is the excess of the purchase price over such fair value and is assigned to one or more reporting units.

The carrying value of goodwill is assessed for impairment annually at year end, or more frequently as economic events dictate, by comparing the fair value of the reporting unit to its carrying value, including goodwill. If the fair value of the reporting unit is less than its carrying value, a goodwill impairment is recognized as the excess of the carrying value of the goodwill over the fair value of the goodwill.

(o) Stock-Based Compensation

The Company maintains stock option, performance share unit (PSU) and deferred stock unit (DSU) plans as described in Note 22.

The Company accounts for stock options granted prior to 2003 based on the intrinsic value at the grant date, which does not result in a charge to earnings because the exercise price was equal to the market price at grant date.

Stock options granted in 2003 are accounted for using the fair value method. Fair values are determined, at the grant date, using the Black-Scholes option-pricing model. The compensation expense associated with these options is charged to earnings over the vesting period with a corresponding increase in contributed surplus. On the exercise of stock options, consideration paid and the associated contributed surplus is credited to common shares.

Stock options granted subsequent to 2003, which provide the holder the right to exercise the stock option or surrender the option for a cash payment, are accounted for based on the intrinsic value at each period end whereby a liability and expense are recorded over the vesting period in the amount by which the then current market price exceeds the option exercise price. When stock options are surrendered for cash, the cash settlement paid reduces the outstanding liability. When stock options are exercised for common shares, consideration paid by the stock option holder and the previously recognized liability associated with the stock options are recorded as share capital.

PSUs are accounted for on a mark-to-market basis over the term of the PSUs whereby a liability and expense are recorded based on the number of PSUs outstanding, the current market price of the Company's shares and the Company's current total shareholder return relative to the selected industry peer group.

DSUs are accounted for on a mark-to-market basis whereby a liability and expense are recorded each period based on the number of DSUs outstanding and the current market price of the Company's shares.

Note 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES *continued*

(p) Employee Future Benefits

The Company's employee future benefit programs consist of both defined benefit and defined contribution pension plans, as well as other post-retirement benefits as described in Note 23.

The costs of pensions and other post-retirement benefits are actuarially determined using the projected benefit method pro-rated based on service and using management's best estimate of expected plan investment performance, discount rates, salary escalation, retirement ages of employees and expected health care costs. For the purpose of calculating the expected return on plan assets, those assets are measured at fair value. The accrued benefit obligation is discounted using a market rate of interest at the end of the year on high quality corporate debt instruments. The excess of the cumulative unamortized net actuarial gain or loss over 10% of the greater of the accrued benefit obligation and the fair value of plan assets at the beginning of the year is amortized over the average remaining service life of active employees.

Company contributions to the defined contribution plan are expensed as incurred.

(q) Hedging and Derivative Financial Instruments

The Company may use derivative financial instruments to manage its exposure to market risks resulting from fluctuations in foreign exchange rates, interest rates and commodity prices. These derivative financial instruments are not used for speculative purposes and a system of controls is maintained that includes a policy covering the authorization, reporting and monitoring of derivative activity.

Derivative instruments that are not designated as hedges for accounting purposes are recorded on the Consolidated Balance Sheet at fair value with any resulting gain or loss recognized in the Consolidated Statement of Earnings in the current period.

The Company formally documents all derivative instruments designated as hedges, the risk management objective and the strategy for undertaking the hedge.

Gains and losses on derivatives that are designated as, and determined to be, effective hedges are deferred and recognized in the period of settlement as a component of the related transaction. The Company assesses, both at inception and over the term of the hedging relationship, whether the derivative instruments used in the hedging transactions are highly effective in offsetting changes in the fair value or cash flows of hedged items. If a derivative instrument ceases to be effective or is terminated, hedge accounting is discontinued. As long as the underlying transaction continues to be probable of occurring, the accumulated gains and losses continue to be deferred and recognized in the Consolidated Statement of Earnings in the period of settlement of the related transaction; future gains or losses are recognized in the Consolidated Statement of Earnings in the period they occur.

Note 2 CHANGES IN ACCOUNTING POLICIES

Stock-Based Compensation for Employees Eligible to Retire Before the Vesting Date

The Company has adopted the recommendations of Emerging Issues Committee Abstract 162, *Stock-based compensation for employees eligible to retire before the vesting date* (EIC 162), for the year ended December 31, 2006. The abstract requires that the compensation cost for a stock option attributable to an employee who is eligible to retire at the grant date be recognized on the grant date if the employee can retire from the entity at any point and the ability to exercise the award does not depend on continued service. It further requires that the compensation cost for a stock option award attributable to an employee who will become eligible to retire during the vesting period be recognized over the period from the grant date to the date the employee becomes eligible to retire.

Previously, stock-based compensation was recognized over the applicable vesting period, without regard to when an employee was eligible to retire. During the year ended December 31, 2006, the Company recorded a cumulative adjustment of $5 million to reflect additional stock-based compensation expense upon adoption of EIC 162. Comparative balances have not been restated as the impact on prior periods is not significant.

Note 3 SEGMENTED INFORMATION FROM CONTINUING OPERATIONS

The Company is an integrated oil and gas company with activities spanning both the upstream and downstream sectors of the industry. The Company conducts its business through five major operating business segments along with Shared Services. Upstream activities are conducted through four business segments, which include North American Natural Gas, East Coast Oil, Oil Sands and International; Downstream operations comprise the fifth business segment.

Upstream operations include the exploration, development, production, transportation and marketing of crude oil, natural gas and natural gas liquids and oil sands. The North American Natural Gas segment includes activity in Western Canada, the U.S. Rockies, the Mackenzie Delta/Corridor, Offshore Nova Scotia and Alaska. The East Coast Oil segment comprises activity offshore Newfoundland and Labrador, and includes interests in the Hibernia, Terra Nova, and White Rose oilfield operations. The Oil Sands segment includes an interest in the Syncrude oil sands mining operation, the MacKay River *in situ* oil sands operation, and an interest in the Fort Hills oil sands mining project. The International segment includes activity in the United Kingdom (U.K.), the Netherlands, Trinidad and Tobago, Venezuela, Libya, Algeria, Tunisia, Denmark, Norway, Morocco and Syria. The producing assets in Syria, previously included in the International segment, have been accounted for as a discontinued operation (Note 4).

The Downstream business segment includes the purchase and sale of crude oil, the refining of crude oil products and the distribution and marketing of these and other purchased products.

Financial information by business segment is presented in the following table as though each segment was a separate business entity. Inter-segment transfers of products, which are accounted for at market value, are eliminated on consolidation. Shared Services includes investment income, interest expense, unrealized gains or losses on translation of foreign currency denominated long-term debt and general corporate revenue and expenses. Shared Services assets are principally cash and cash equivalents and other general corporate assets.

	UPSTREAM					
	NORTH AMERICAN NATURAL GAS			EAST COAST OIL		
	2006	2005	2004	**2006**	2005	2004
Revenue[1]						
Sales to customers	**$ 1,504**	$ 2,073	$ 1,770	**$ 2,004**	$ 1,284	$ 914
Investment and other income (expense)[2]	**6**	21	3	**-**	(2)	(3)
Inter-segment sales	**349**	345	215	**298**	346	527
Segmented revenue	**1,859**	2,439	1,988	**2,302**	1,628	1,438
Expenses						
Crude oil and product purchases	**256**	466	359	**452**	48	-
Inter-segment transactions	**5**	7	9	**9**	6	5
Operating, marketing and general	**462**	426	379	**245**	158	120
Exploration	**150**	118	119	**12**	4	2
Depreciation, depletion and amortization	**402**	364	321	**237**	259	268
Unrealized gain on translation of foreign currency denominated long-term debt	**-**	-	-	**-**	-	-
Interest	**-**	-	-	**-**	-	-
	1,275	1,381	1,187	**955**	475	395
Earnings (loss) from continuing operations before income taxes	**584**	1,058	801	**1,347**	1,153	1,043
Provision for income taxes						
Current	**351**	311	330	**434**	361	323
Future *(Note 7)*	**(172)**	73	(29)	**(21)**	17	9
	179	384	301	**413**	378	332
Net earnings (loss) from continuing operations	**$ 405**	$ 674	$ 500	**$ 934**	$ 775	$ 711
Capital and exploration expenditures from continuing operations						
Property, plant and equipment and exploration expenditures	**$ 788**	$ 713	$ 666	**$ 256**	$ 314	$ 275
Deferred charges and other assets	**5**	7	6	**-**	1	1
Acquisition of Prima Energy Corporation, including goodwill	**-**	-	644	**-**	-	-
	$ 793	$ 720	$ 1,316	**$ 256**	$ 315	$ 276
Cash flow from continuing operating activities	**$ 651**	$ 1,219	$ 899	**$ 1,129**	$ 1,002	$ 1,018
Total assets from continuing operations	**$ 4,151**	$ 3,763	$ 3,477	**$ 2,465**	$ 2,442	$ 2,265

	UPSTREAM					
	OIL SANDS			INTERNATIONAL		
	2006	2005	2004	**2006**	2005	2004
Revenue[1]						
Sales to customers	**$ 592**	$ 749	$ 412	**$ 2,464**	$ 2,183	$ 1,767
Investment and other income (expense)[2]	**-**	4	-	**(283)**	(851)	(335)
Inter-segment sales	**822**	660	548	**-**	-	-
Segmented revenue	**1,414**	1,413	960	**2,181**	1,332	1,432
Expenses						
Crude oil and product purchases	**425**	571	291	**-**	-	-
Inter-segment transactions	**31**	80	49	**-**	-	-
Operating, marketing and general	**508**	423	362	**350**	364	319
Exploration	**21**	32	16	**156**	117	98
Depreciation, depletion and amortization	**128**	133	69	**323**	249	320
Unrealized gain on translation of foreign currency denominated long-term debt	**-**	-	-	**-**	-	-
Interest	**-**	-	-	**-**	-	-
	1,113	1,239	787	**829**	730	737
Earnings (loss) from continuing operations before income taxes	**301**	174	173	**1,352**	602	695
Provision for income taxes						
Current	**(53)**	(45)	(71)	**1,248**	1,015	631
Future *(Note 7)*	**109**	104	124	**310**	(304)	(52)
	56	59	53	**1,558**	711	579
Net earnings (loss) from continuing operations	**$ 245**	$ 115	$ 120	**$ (206)**	$ (109)	$ 116
Capital and exploration expenditures from continuing operations						
Property, plant and equipment and exploration expenditures	**$ 377**	$ 772	$ 397	**$ 760**	$ 696	$ 1,707
Deferred charges and other assets	**1**	1	-	**-**	-	-
Acquisition of Prima Energy Corporation, including goodwill	**-**	-	-	**-**	-	-
	$ 378	$ 773	$ 397	**$ 760**	$ 696	$ 1,707
Cash flow from continuing operating activities	**$ 499**	$ 340	$ 384	**$ 840**	$ 722	$ 789
Total assets from continuing operations	**$ 2,885**	$ 2,623	$ 1,883	**$ 6,031**	$ 4,856	$ 4,969

Note 3 SEGMENTED INFORMATION FROM CONTINUING OPERATIONS *continued*

	DOWNSTREAM			SHARED SERVICES		
	2006	2005	2004	**2006**	2005	2004
Revenue[1]						
Sales to customers	**$ 12,347**	$ 11,296	$ 9,407	**$ -**	$ -	$ -
Investment and other income (expense)[2]	**19**	43	13	**16**	(21)	10
Inter-segment sales	**15**	13	14	**-**	-	-
Segmented revenue	**12,381**	11,352	9,434	**16**	(21)	10
Expenses						
Crude oil and product purchases	**8,517**	7,762	6,093	**(1)**	(1)	(3)
Inter-segment transactions	**1,439**	1,271	1,241	**-**	-	-
Operating, marketing and general	**1,495**	1,436	1,328	**120**	155	64
Exploration	**-**	-	-	**-**	-	-
Depreciation, depletion and amortization	**262**	216	277	**13**	1	1
Unrealized gain on translation of foreign currency denominated long-term debt	**-**	-	-	**(1)**	(88)	(77)
Interest	**-**	-	-	**165**	164	142
	11,713	10,685	8,939	**296**	231	127
Earnings (loss) from continuing operations before income taxes	**668**	667	495	**(280)**	(252)	(117)
Provision for income taxes						
Current	**141**	264	226	**(48)**	(112)	(74)
Future *(Note 7)*	**54**	(12)	(45)	**31**	37	20
	195	252	181	**(17)**	(75)	(54)
Net earnings (loss) from continuing operations	**$ 473**	$ 415	$ 314	**$ (263)**	$ (177)	$ (63)
Capital and exploration expenditures from continuing operations						
Property, plant and equipment and exploration expenditures	**$ 1,229**	$ 1,053	$ 839	**$ 24**	$ 12	$ 9
Deferred charges and other assets	**22**	33	26	**22**	28	3
Acquisition of Prima Energy Corporation, including goodwill	**-**	-	-	**-**	-	-
	$ 1,251	$ 1,086	$ 865	**$ 46**	$ 40	$ 12
Cash flow from continuing operating activities	**$ 835**	$ 663	$ 879	**$ (346)**	$ (163)	$ (41)
Total assets from continuing operations	**$ 6,649**	$ 5,609	$ 4,462	**$ 465**	$ 714	$ 95

	CONSOLIDATED		
	2006	2005	2004
Revenue[1]			
Sales to customers	**$ 18,911**	$ 17,585	$ 14,270
Investment and other income (expense)[2]	**(242)**	(806)	(312)
Inter-segment sales			
Segmented revenue	**18,669**	16,779	13,958
Expenses			
Crude oil and product purchases	**9,649**	8,846	6,740
Inter-segment transactions			
Operating, marketing and general	**3,180**	2,962	2,572
Exploration	**339**	271	235
Depreciation, depletion and amortization	**1,365**	1,222	1,256
Unrealized gain on translation of foreign currency denominated long-term debt	**(1)**	(88)	(77)
Interest	**165**	164	142
	14,697	13,377	10,868
Earnings (loss) from continuing operations before income taxes	**3,972**	3,402	3,090

Provision for income taxes					
Current		**2,073**		1,794	1,365
Future *(Note 7)*		**311**		(85)	27
		2,384		1,709	1,392
Net earnings (loss) from continuing operations	**$**	**1,588**	$	1,693	$ 1,698
Capital and exploration expenditures from continuing operations					
Property, plant and equipment and exploration expenditures	**$**	**3,434**	$	3,560	$ 3,893
Deferred charges and other assets		**50**		70	36
Acquisition of Prima Energy Corporation, including goodwill		**-**		-	644
	$	**3,484**	$	3,630	$ 4,573
Cash flow from continuing operating activities	**$**	**3,608**	$	3,783	$ 3,928
Total assets from continuing operations	**$**	**22,646**	$	20,007	$ 17,151

1 There were no customers that represented 10% or more of the Company's consolidated revenues for the periods presented.
2 Investment and other income for the International segment includes $259 million (2005 - $889 million; 2004 - $333 million) of unrealized losses relating to the Buzzard derivative contracts (Note 24).

Note 3 SEGMENTED INFORMATION FROM CONTINUING OPERATIONS *continued*

Geographic Information from Continuing Operations

	2006		2005		2004	
	Revenues	**Total Assets**	Revenues	Total Assets	Revenues	Total Assets
Canada	**$ 16,295**	**$ 14,736**	$ 15,302	$ 14,261	$ 12,472	$ 11,263
Foreign[1]	**2,374**	**7,910**	1,477	5,746	1,486	5,888
	$ 18,669	**$ 22,646**	$ 16,779	$ 20,007	$ 13,958	$ 17,151

1 Foreign total assets include $3,692 million relating to assets in the U.K. (2005 - $2,964 million; 2004 - $1,002 million).

Note 4 DISCONTINUED OPERATIONS

On January 31, 2006, the Company completed the sale of its producing assets in Syria for net proceeds of $640 million, resulting in a gain on disposal of $134 million.

The accounting for discontinued operations results in a reduction of the Consolidated Statement of Earnings balances as follows:

	2006	2005	2004
Revenue	**$ 168** [1]	$ 464	$ 419
Expenses			
Operating, marketing and general	**6**	104	118
Depreciation, depletion and amortization	**-**	145	146
	6	249	264
Earnings from discontinued operations before income taxes	**162**	215	155
Provision for income taxes	**10**	117	96
Net earnings from discontinued operations	**$ 152**	$ 98	$ 59

The assets and liabilities of the discontinued operations are comprised of the following:

	2006	2005
Assets		
Current assets	**$ -**	$ 237 [2]
Property, plant and equipment, net	**-**	300
Goodwill	**-**	111
Total assets	**$ -**	$ 648
Liabilities		
Current liabilities	**$ -**	$ 102
Net assets of discontinued operations	**$ -**	$ 546

1 Revenue includes the gain on disposal of $134 million.
2 Current assets include cash and cash equivalents of $68 million as at December 31, 2005.

Note 5 INVESTMENT AND OTHER INCOME (EXPENSE)

Investment and other income includes net losses on derivative contracts (Note 24) of $257 million (2005 - $882 million; 2004 - $345 million) and net gains on disposal of assets of $30 million (2005 - $48 million; 2004 - $12 million) for the year ended December 31, 2006.

Note 6 ASSET WRITE-DOWNS

Oakville Refining Operations

Petro-Canada announced in September 2003 it would cease the Oakville refining operations and expand the existing terminalling facilities. The shutdown of the refinery was completed in April 2005. The total charge to earnings related to the shutdown over the three years was $195 million after-tax. The following expenses have been recorded in the Downstream segment:

	2006		2005		2004	
	Pre-Tax	**After-Tax**	Pre-Tax	After-Tax	Pre-Tax	After-Tax
Operating, marketing and general expenses (de-commissioning and employee-related costs)	**$ -**	**$ -**	$ (4)	$ (2)	$ 3	$ 2
Depreciation and amortization expenses (asset write-downs and increased depreciation)	**-**	**-**	1	-	71	44
	$ -	**$ -**	$ (3)	$ (2)	$ 74	$ 46

Note 7 INCOME TAXES

The computation of the provision for income taxes is as follows:

	2006	2005	2004
Earnings from continuing operations before income taxes	**$ 3,972**	$ 3,402	$ 3,090
Add (deduct):			
Non-deductible royalties and other payments to provincial governments, net	**61**	393	352
Resource allowance	**(158)**	(413)	(512)
Non-taxable foreign exchange	**(1)**	(45)	(40)
Other	**(24)**	5	(10)
Earnings from continuing operations as adjusted before income taxes	**$ 3,850**	$ 3,342	$ 2,880
Canadian federal income tax rate	**38.0%**	38.0%	38.0%
Income tax on earnings from continuing operations as adjusted at Canadian federal income tax rate	**$ 1,463**	$ 1,270	$ 1,094
Provincial income taxes	**295**	325	271
Federal - abatement and other credits	**(262)**	(378)	(274)
Current income tax increase due to provincial reassessments	**70**	-	-
Future income tax increase (decrease) due to Canadian federal and provincial rate changes	**(63)**	6	(13)
Future income tax increase due to foreign rate changes	**242**	-	-
Higher foreign income tax rates	**627**	482	320
Income tax credits and other	**12**	4	(6)
Provision for income taxes	**$ 2,384**	$ 1,709	$ 1,392
Effective income tax rate on earnings from continuing operations before income taxes	**60.0%**	50.2%	45.0%

The provision for income taxes is comprised of:

	2006	2005	2004
Current			
Canadian	**$ 801**	$ 769	$ 734
Foreign	**1,272**	1,025	631
Future			
Canadian	**62**	(113)	(54)
Foreign	**249**	28	81
Total provision for income taxes	**$ 2,384**	$ 1,709	$ 1,392

Note 7 INCOME TAXES *continued*

The provision for future income taxes for the year ended December 31, 2006 includes a $242 million charge due to the enacted increase in the U.K. supplemental corporate income tax rate. The adjustment was allocated to the Company's International business segment.

The provision for future income taxes for the year ended December 31, 2006 was reduced by $63 million due to the enacted reduction in Canadian federal and provincial income tax rates. The adjustment was allocated to the segments as a decrease (increase) to the tax provision as follows: North American Natural Gas - $6 million, East Coast Oil - $37 million, Oil Sands - $44 million, International –$(64) million, Downstream - $41 million and Shared Services - $(1) million.

The provision for current income taxes for the year ended December 31, 2006 was increased by $70 million due to the Quebec government enacting retroactive tax legislation. The adjustment was allocated to Shared Services.

The following table summarizes the temporary differences that give rise to the net future income tax asset and liability:

		2006		2005
Future income tax liabilities				
Property, plant and equipment	**$**	**3,919**	$	3,114
Partnership income [1]		**367**		532
Deferred charges and other assets		**75**		58
Future income tax assets				
Asset retirement obligations and other liabilities		**(1,010)**		(906)
Inventories		**(212)**		(230)
Other		**(260)**		(163)
Future income tax liability		**2,879**		2,405
Less: Current future income tax asset		**(95)**		-
Net future income tax liability	**$**	**2,974**	$	2,405

1 Taxable income for certain Canadian upstream activities are generated by a partnership and the related taxes will be included in current income taxes in the next year.

Deferred distribution taxes associated with International business operations have not been recorded. Based on current plans, repatriation of funds in excess of foreign reinvestment will not result in material additional income tax expense.

Complex income tax issues, which involve interpretations of continually changing regulations, are encountered in computing the provision for income taxes. Management believes that adequate provisions have been made for all such outstanding issues and that the resolution of these issues would not materially affect the financial position or results of operations of the Company.

Note 8 EARNINGS PER SHARE

The weighted-average number of common shares outstanding used in the calculations of basic and diluted earnings per share from continuing operations and earnings per share, assuming that all dilutive outstanding stock options were exercised, was:

(millions)	**2006**	2005	2004
Weighted-average number of common shares outstanding - basic	**503.9**	518.4	529.3
Effect of dilutive stock options	**6.0**	7.0	6.9
Weighted-average number of common shares outstanding - diluted	**509.9**	525.4	536.2

There were no stock options excluded from the diluted earnings per share from continuing operations and earnings per share calculations. Stock options are excluded when the exercise price exceeds the average share price in a respective period.

Note 9 CASH FLOW INFORMATION

Changes in Non-Cash Working Capital

Non-cash working capital is comprised of current assets and current liabilities, other than cash and cash equivalents and the current portion of long-term debt.

The (increase) decrease in non-cash working capital is comprised of:

		2006		2005		2004
Operating activities from continuing operations						
Accounts receivable	**$**	**17**	$	(563)	$	(131)
Inventories		**(36)**		(18)		4
Accounts payable and accrued liabilities		**365**		662		266
Income taxes payable		**(60)**		(190)		96
Current portion of long-term liabilities and other		**(365)**		25		(131)
	$	**(79)**	$	(84)	$	104
Investing activities						
Accounts payable and accrued liabilities	**$**	**59**	$	(12)	$	10
Other liabilities		**-**		249		-
	$	**59**	$	237	$	10
Financing activities						
Accounts payable and accrued liabilities	**$**	**-**	$	-	$	(26)

Cash Payments

Cash payments from continuing operations for interest and income taxes were as follows:

		2006		2005		2004
Interest	**$**	**194**	$	186	$	165
Income taxes	**$**	**2,149**	$	1,972	$	1,353

Note 10 SECURITIZATION PROGRAM

In 2004, the Company entered into a securitization program, expiring in 2009, to sell an undivided interest of eligible accounts receivable up to $400 million to a third party, on a revolving and fully serviced basis. The service liability has been estimated to be insignificant. The Company also retains an interest in the transferred accounts receivable equal to the required reserves amount.

In March 2005, the Company increased the limit to sell eligible accounts receivable under the program from $400 million to $500 million. During the year ended December 31, 2005, the Company sold an additional $80 million of outstanding receivables for net proceeds of $80 million. As at December 31, 2006, $480 million (December 31, 2005 - $480 million) of outstanding accounts receivable had been sold under the program for net proceeds of $479 million.

Note 11 FORT HILLS OIL SANDS MINING PROJECT

In June 2005, the Company acquired, for $300 million, a 60% interest in the Fort Hills oil sands mining project, which was previously wholly owned by UTS Energy Corporation (UTS). As part of the acquisition, Petro-Canada became the project operator. To pay for the investment, Petro-Canada will fund a portion of UTS' share of the next $2.5 billion of development capital. The discounted value of the acquisition cost was recorded in other liabilities (Note 19).

In November 2005, the Company and UTS finalized agreements with Teck Cominco Limited (Teck Cominco) whereby Teck Cominco acquired a 15% interest in the Fort Hills oil sands mining project with Petro-Canada and UTS holding interests of 55% and 30%, respectively. Petro-Canada remains the project operator.

Note 12 ACQUISITION OF PRIMA ENERGY CORPORATION

On July 28, 2004, the Company acquired all of the common shares of Prima Energy Corporation, an oil and gas company with operations in the U.S. Rockies, for a total acquisition cost of $644 million, net of cash acquired. The results of operations were included in the Consolidated Financial Statements from the date of acquisition.

The acquisition was accounted for by the purchase method of accounting. The allocation of fair value to the assets acquired and liabilities assumed was:

Property, plant and equipment	$	688
Goodwill		193
Current assets, excluding cash of $74 million		36
Deferred charges and other assets		2
Total assets acquired		919
Current liabilities		41
Future income taxes		217
Asset retirement obligations and other liabilities		17
Total liabilities assumed		275
Net assets acquired	$	644

Goodwill, which is not tax deductible, was assigned to the Company's North American Natural Gas business segment.

Note 13 CASH AND CASH EQUIVALENTS

		2006		2005
Cash	**$**	**42**	$	48
Short-term investments		**457**		741
		499		789
Less: discontinued operations *(Note 4)*		**-**		68
	$	**499**	$	721

Note 14 INVENTORIES

		2006		2005
Crude oil, refined products and merchandise	**$**	**455**	$	431
Materials and supplies		**177**		165
	$	**632**	$	596

Note 15 PROPERTY, PLANT AND EQUIPMENT

	2006			2005			2006	2005
	Cost	**Accumulated Depreciation, Depletion and Amortization**	**Net**	Cost	Accumulated Depreciation, Depletion and Amortization	Net	Expenditures on Property, Plant and Equipment[1,2]	
Upstream								
North American Natural Gas	**$ 6,942**	**$ 3,189**	**$ 3,753**	$ 6,161	$ 2,828	$ 3,333	**$ 707**	$ 635
East Coast Oil	**3,874**	**1,594**	**2,280**	3,577	1,359	2,218	**248**	310
Oil Sands	**3,598**	**908**	**2,690**	3,217	759	2,458	**370**	745
International	**5,863**	**1,123**	**4,740**	4,245	469	3,776	**733**	665
	20,277	**6,814**	**13,463**	17,200	5,415	11,785	**2,058**	2,355
Downstream								
Refining	**5,333**	**1,469**	**3,864**	4,254	1,318	2,936	**1,083**	936
Marketing and other	**2,517**	**1,301**	**1,216**	2,419	1,252	1,167	**146**	117
	7,850	**2,770**	**5,080**	6,673	2,570	4,103	**1,229**	1,053
Other property, plant and equipment	**495**	**461**	**34**	470	437	33	**24**	12
	$ 28,622	**$ 10,045**	**$ 18,577**	$ 24,343	$ 8,422	$ 15,921	**$ 3,311**	$ 3,420

1 Expenditures are from continuing operations and exclude $1 million (2005 - $46 million) relating to discontinued operations (Note 4).
2 Exploration expenses, excluding general and administrative and geological and geophysical expenses, of $123 million (2005 - $140 million; 2004 - $117 million) are reclassified from operating activities and included with expenditures on property, plant and equipment and exploration under investing activities in the Consolidated Statement of Cash Flows.

Property, plant and equipment net cost includes asset retirement costs of $609 million (2005 - $414 million).

Interest capitalized during 2006 amounted to $51 million (2005 - $35 million; 2004 - $20 million).

Costs of $62 million (2005 - $48 million) relating to East Coast Oil projects, $2,934 million (2005 - $2,778 million) relating to the International operations, $1,044 million (2005 - $1,227 million) relating to Downstream operations, $152 million (2005 - $1,190 million) relating to Oil Sands operations and $211 million (2005 - $323 million) relating to North American Natural Gas operations are currently not being depleted or depreciated.

Capital leases at a net cost of $60 million (2005 - $63 million) and $23 million (2005 - $25 million) are included in the assets of East Coast Oil and Oil Sands, respectively (Note 18).

Note 16 GOODWILL

The following table summarizes the changes in goodwill:

	2006			2005		
	North American Natural Gas	**International**	**Total**	North American Natural Gas	International	Total
Goodwill at beginning of year	**$ 170**	**$ 567**	**$ 737**	$ 175	$ 811	$ 986
Foreign exchange	**(1)**	**65**	**64**	(5)	(133)	(138)
Discontinued operations *(Note 4)*	**-**	**-**	**-**	-	(111)	(111)
Goodwill at end of year	**$ 169**	**$ 632**	**$ 801**	$ 170	$ 567	$ 737

Note 17 DEFERRED CHARGES AND OTHER ASSETS

		2006		2005
Investments	$	**82**	$	87
Accrued pension asset *(Note 23)*		**128**		105
Deferred financing costs		**101**		108
Other long-term assets		**131**		115
	$	**442**	$	415

Note 18 LONG-TERM DEBT

	Maturity		2006		2005
Debentures and notes					
5.95% unsecured senior notes ($600 million US)[1]	2035	$	**699**	$	700
5.35% unsecured senior notes ($300 million US)[2]	2033		**349**		350
7.00% unsecured debentures ($250 million US)	2028		**291**		292
7.875% unsecured debentures ($275 million US)	2026		**321**		321
9.25% unsecured debentures ($300 million US)	2021		**349**		350
5.00% unsecured senior notes ($400 million US)	2014		**466**		466
4.00% unsecured senior notes ($300 million US)[2]	2013		**349**		350
Capital leases *(Note 15)*[3]	2007-2017		**70**		77
Retail licensee trust loans			**-**		7
			2,894		2,913
Current portion			**(7)**		(7)
		$	**2,887**	$	2,906

1 In May 2005, the Company issued $600 million US 5.95% notes due May 15, 2035. The proceeds were used primarily to repay existing short-term notes payable.
2 In anticipation of issuing these senior notes, the Company entered into interest rate derivatives which resulted in effective interest rates of 6.073% for the 5.35% notes due in 2033 and 4.838% for the 4.00% notes due in 2013.
3 The Company is party to one transportation and one time charter agreement that are accounted for as capital leases and have implicit rates of interest of 14.65% and 11.90%, respectively. The aggregate remaining repayments under the transportation and time charter agreements are $70 million, including the following amounts in the next five years: 2007 - $7 million; 2008 - $2 million; 2009 - $3 million; 2010 - $3 million; and 2011 - $4 million.

Interest on long-term debt, net of capitalized interest, was $152 million in 2006 (2005 - $146 million; 2004 - $132 million).

At December 31, 2006, the Company has in place syndicated operating credit facilities totalling $2,200 million, maturing in 2012. The syndicated facilities are unsecured, committed revolving facilities that bear interest at either the lenders' rates for Canadian prime loans, U.S. base rate loans, Bankers' Acceptances rates or at London Inter-Bank Offered Rate (LIBOR) plus applicable margins. The Company also has revolving bilateral demand credit facilities of $829 million at December 31, 2006. A total of $1,444 million of the credit facilities was used for letters of credit and overdraft coverage at December 31, 2006. The syndicated facilities also provide liquidity support to Petro-Canada's commercial paper program, under which no amounts were outstanding at December 31, 2006.

Note 19 OTHER LIABILITIES

		2006		2005
Post-retirement benefits *(Note 23)*	**$**	**182**	$	173
Unrealized loss on Buzzard derivative contracts *(Note 24)*		**1,252**		1,222
Fort Hills purchase obligation *(Note 11)*		**170**		247
Other long-term liabilities		**222**		246
	$	**1,826**	$	1,888

Note 20 ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations are recorded for obligations where the Company will be required to retire tangible long-lived assets such as well sites, offshore production platforms, natural gas processing plants and marketing sites.

The following table summarizes the changes in the asset retirement obligations:

		2006		2005
Asset retirement obligations at beginning of year	**$**	**962**	$	873
Obligations incurred		**95**		92
Changes in estimates		**138**		104
Abandonment expenditures		**(55)**		(98)
Accretion expense		**54**		50
Foreign exchange		**43**		(59)
Asset retirement obligations at end of year		**1,237**		962
Less: Current portion		**(67)**		(80)
	$	**1,170**	$	882

In determining the fair value of the asset retirement obligations, the estimated cash flows of new obligations incurred during the year have been discounted at 5.5% (2005 - 5.5%). The total undiscounted amount of the estimated cash flows required to settle the obligations is $3,481 million (2005 - $2,839 million). The obligations will be settled on an ongoing basis over the useful lives of the operating assets, which extend up to 50 years in the future. The current portion of asset retirement obligations is included in accounts payable and accrued liabilities.

Note 21 SHAREHOLDERS' EQUITY

Authorized

The authorized share capital is comprised of an unlimited number of:

(a) Preferred shares issuable in series designated as Senior Preferred Shares
(b) Preferred shares issuable in series designated as Junior Preferred Shares
(c) Common shares without par value

Issued and Outstanding

Changes in common shares and contributed surplus were as follows:

	2006						2005				
	Shares		**Amount**		**Contributed Surplus**	Shares		Amount		Contributed Surplus
Balance at beginning of year	**515,138,904**	**$**	**1,362**	**$**	**1,422**	519,928,022	$	1,314	$	1,743
Issued under employee stock-option and share purchase plans	**2,177,881**		**57**		**5**	3,544,282		70		3
Repurchased under normal course issuer bid	**(19,778,400)**		**(53)**		**(958)**	(8,333,400)		(22)		(324)
Balance at end of year	**497,538,385**	$	**1,366**	**$**	**469**	515,138,904	$	1,362	$	1,422

Note 21 SHAREHOLDERS' EQUITY *continued*

In June 2006, the Company renewed its normal course issuer bid to repurchase up to 25 million of its common shares during the period from June 22, 2006 to June 21, 2007, subject to certain conditions. During 2006, the Company purchased 19,778,400 common shares at an average price of $51.10 per common share for a total cost of $1,011 million (2005 - 8,333,400 common shares at an average price of $41.54 per common share for a total cost of $346 million). The excess of the purchase price over the carrying amount of the shares purchased, which totalled $958 million in 2006 (2005 - $324 million), was recorded as a reduction of contributed surplus.

Note 22 STOCK-BASED COMPENSATION

Stock Options

The Company maintains a stock option plan whereby options can be granted to officers and certain employees for up to 44 million common shares. Stock options have a term of 10 years if granted prior to 2004 and seven years if granted subsequent to 2003. All stock options vest over periods of up to four years and are exercisable at the market prices for the shares on the dates that the options were granted.

In 2004, the Company amended the option plan to provide the holder of stock options granted subsequent to 2003 the alternative to exercise these options as a cash payment alternative (CPA). Where the CPA is chosen, vested options can be surrendered for cancellation in return for a direct cash payment from the Company based on the excess of the then market price over the option exercise price.

Changes in the number of outstanding stock options were as follows:

	2006		2005		2004	
	Number	**Weighted-Average Exercise Price *(dollars)***	Number	Weighted-Average Exercise Price *(dollars)*	Number	Weighted-Average Exercise Price *(dollars)*
Balance at beginning of year	**18,361,617**	**$ 24**	18,074,698	$ 21	17,241,186	$ 19
Granted	**4,911,600**	**52**	4,185,800	35	3,673,400	29
Exercised for common shares	**(2,177,881)**	**20**	(3,544,282)	18	(2,492,000)	16
Surrendered for cash payment	**(119,710)**	**31**	(47,551)	29	-	-
Cancelled	**(260,893)**	**41**	(307,048)	29	(347,888)	22
Balance at end of year	**20,714,733**	**$ 31**	18,361,617	$ 24	18,074,698	$ 21

The following stock options were outstanding as at December 31, 2006:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices *(dollars)*	Number	Weighted-Average Life *(years)*	Weighted-Average Exercise Price *(dollars)*	Number	Weighted-Average Exercise Price *(dollars)*
$ 8 to 17	3,729,484	3.8	$ 14	3,729,484	$ 14
18 to 23	2,117,975	4.2	19	2,117,975	19
24 to 27	3,222,529	5.9	26	2,239,203	26
28 to 32	3,001,770	4.1	29	1,392,070	29
33 to 42	3,868,575	5.1	35	954,050	35
43 to 55	4,774,400	6.1	52	81,900	52
$ 8 to 55	20,714,733	5.0	$ 31	10,514,682	$ 22

During 2006, the Company recorded compensation expense of $10 million (2005 - $10 million; 2004 - $10 million) relating to the 2003 stock options and $31 million (2005 - $69 million; 2004 - $3 million) relating to options with a CPA (Note 2).

Note 22 STOCK-BASED COMPENSATION *continued*

Performance Share Units

The Company maintains a Performance Share Unit (PSU) plan for officers and other senior management employees. Under the PSU program, notional share units are awarded and settled in cash at the end of a three-year period based upon the Company's share price at that time, the value of notional dividends applied during the period and the Company's total shareholder return relative to a peer group of North American industry competitors.

Changes in the number of outstanding PSUs were as follows:

	2006 Number	2005 Number
Balance at beginning of year	**1,158,967**	565,860
Granted	**385,632**	642,940
Exercised	**-**	-
Cancelled	**(61,613)**	(49,833)
Balance at end of year	**1,482,986**	1,158,967

PSUs outstanding at the end of 2004 have a performance period ending in 2007, PSUs issued in 2005 have a performance period ending in 2008 and PSUs issued in 2006 have a performance period ending in 2009. During 2006, the Company recorded compensation (recovery) expense relating to PSUs of $(4) million (2005 - $7 million; 2004 - nil).

Deferred Share Units

The Company maintains a Deferred Share Unit (DSU) plan whereby executive officers are awarded DSUs and/or can elect to receive all or a portion of their annual incentive compensation in the form of DSUs. Under the officer DSU program, notional share units are issued for the elected amount, which is based on the then current market price of the Company's common shares. Upon termination or retirement, the units are settled in cash, which includes an amount for the value of notional dividends earned over the period the units were outstanding.

The Company's Board of Directors receives a portion of their compensation in the form of DSUs and can also elect to receive all or a portion of their non-DSU compensation in the form of DSUs. Under the Director program, notional share units are issued and settled in cash or common shares, including the value of notional dividends, upon ceasing to be a Director.

During 2006, the Company recorded compensation expense (recovery) relating to DSUs of $2 million (2005 - $13 million; 2004 - $(1) million).

Note 23 EMPLOYEE FUTURE BENEFITS

The Company maintains pension plans with defined benefit and defined contribution provisions and provides certain health care and life insurance benefits to its qualifying retirees. The actuarially determined cost of these benefits is accrued over the estimated service life of employees. The defined benefit provisions are generally based upon years of service and average salary during the final years of employment. Certain defined benefit options require employee contributions and the balance of the funding for the registered plans is provided by the Company, based upon the advice of an independent actuary. The accrued benefit obligations and the fair value of plan assets are measured for accounting purposes at December 31 of each year. The most recent actuarial valuation of the pension plan for funding purposes was as of December 31, 2004 and the next required valuation will be as of December 31, 2007.

The defined contribution plan provides for an annual contribution of 5% to 8% of each participating employee's pensionable earnings.

Note 23 EMPLOYEE FUTURE BENEFITS *continued*

Benefit Plan Expense

	Pension Plans			Other Post-Retirement Plans		
	2006	2005	2004	**2006**	2005	2004
(a) Defined benefit plans						
Employer current service cost	**$ 40**	$ 36	$ 31	**$ 4**	$ 4	$ 4
Interest cost	**86**	86	81	**11**	12	13
Actual return on plan assets	**(154)**	(133)	(91)	**-**	-	-
Actuarial losses (gains)	**43**	155	97	**-**	19	(15)
Elements of employee future benefit plan expense before adjustments to recognize the long-term nature of employee future benefit plan expense	**15**	144	118	**15**	35	2
Difference between actual and expected return on plan assets	**55**	45	12	**-**	-	-
Difference between actual and recognized actuarial losses in year	**8**	(121)	(67)	**2**	(19)	16
Amortization of transitional (asset) obligation	**(5)**	(6)	(5)	**2**	2	2
	73	62	58	**19**	18	20
(b) Defined contribution plans	**18**	16	13			
Total expense	**$ 91**	$ 78	$ 71	**$ 19**	$ 18	$ 20

Benefit Plan Funding

	Pension Plans			Other Post-Retirement Plans		
Defined contribution	**$ 18**	$ 16	$ 13			
Defined benefit	**$ 96**	$ 96	$ 80	**$ 10**	$ 9	$ 9

Financial Status of Defined Benefit Plans

	Pension Plans		Other Post-Retirement Plans	
	2006	2005	**2006**	2005
Fair value of plan assets	**$ 1,486**	$ 1,303	**$ -**	$ -
Accrued benefit obligation	**1,786**	1,681	**235**	230
Funded status - plan deficit[1]	**(300)**	(378)	**(235)**	(230)
Unamortized transitional (asset) obligation	**(18)**	(23)	**13**	15
Unamortized net actuarial losses	**446**	506	**40**	42
Accrued benefit asset (liability)	**$ 128**	$ 105	**$ (182)**	$ (173)

Reconciliation of Plan Assets

	Pension Plans		Other Post-Retirement Plans	
	2006	2005	**2006**	2005
Fair value of plan assets at beginning of year	**$ 1,303**	$ 1,157	**$ -**	$ -
Contributions	**96**	96	**10**	9
Benefits paid	**(77)**	(83)	**(10)**	(9)
Actual gain (loss) on plan assets	**154**	133	**-**	-
Other	**10**	-	**-**	-
Fair value of plan assets at end of year	**$ 1,486**	$ 1,303	**$ -**	$ -

Reconciliation of Accrued Benefit Obligation

	Pension Plans		Other Post-Retirement Plans	
	2006	2005	**2006**	2005
Accrued benefit obligation at beginning of year	**$ 1,681**	$ 1,487	**$ 230**	$ 204
Current service cost	**40**	36	**4**	4
Interest cost	**86**	86	**11**	12
Benefits paid	**(77)**	(83)	**(10)**	(9)
Actuarial losses (gains)	**43**	155	**-**	19
Other	**13**	-	**-**	-
Accrued benefit obligation at end of year	**$ 1,786**	$ 1,681	**$ 235**	$ 230

1 The pension and other post-retirement plans included in the financial status information are not fully funded.

Note 23 EMPLOYEE FUTURE BENEFITS *continued*

Defined Benefit and Other Post-Retirement Plans Assumptions

	2006	2005	2004
Year-end obligation discount rate[1]	**5.0%**	5.0%	5.7%
Accrued benefit obligation discount rate[1]	**5.0%**	5.7%	6.0%
Long-term rate of return on plan assets	**7.5%**	7.5%	7.5%
Rate of compensation increase, excluding merit increases	**3.0%**	3.1%	3.0%

1 Assumption used in both pension and other post-retirement plans.

Assumed Health and Dental Care Cost Trend Rates at December 31 are as follows:

	2006	2005
Dental care cost trend rate[1]	**3.5%**	3.5%
Health care cost trend rate	**8.0%**	8.5%
Health care cost trend rate declines to	**4.5%**	4.5%
Year that health care cost trend rate reaches the rate which it is expected to remain at	**2014**	2014

1 Dental care cost trend rate assumed to remain constant.

Sensitivity Analysis

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects for 2006:

	Increase	Decrease
Total of service and interest cost	$ 2	$ (2)
Accrued benefit obligation	$ 28	$ (26)

The Plan Assets consist of:

	Percentage of Plan Assets at December 31,	
Asset Category	**2006**	2005
Equity	**62%**	61%
Bonds	**38%**	39%
	100%	100%

Note 24 FINANCIAL INSTRUMENTS AND DERIVATIVES

The Company is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of its business operations. The Company monitors its exposure to market fluctuations and may use derivative instruments to manage these risks, as it considers appropriate.

Crude Oil and Products

The Company enters into forward contracts and options to reduce exposure to Downstream margin fluctuations, including margins on fixed-price product sales, and short-term price fluctuations on the purchase of foreign and domestic crude oil and refined products.

The Company has also entered into a series of forward sales contracts for the future sale of Brent crude oil in connection with its 2004 acquisition of an interest in the Buzzard field in the U.K. sector of the North Sea. Unrealized losses relating to these contracts amounted to $259 million for the year ended December 31, 2006 (2005 - $889 million; 2004 - $333 million).

Investment and other income includes unrealized losses on all derivative contracts of $268 million for the year ended December 31, 2006 (2005 - $889 million; 2004 - $338 million).

As at December 31, 2006, the amounts included in the Consolidated Balance Sheet as a result of the unrealized mark-to-market amounts on derivative contracts are as follows:

		December 31, 2006		December 31, 2005
Accounts receivable	**$**	**-**	$	5
Accounts payable and accrued liabilities		**233**		1
Other liabilities		**1,252**		1,222

The Company's outstanding contracts for derivative instruments and the related fair values at December 31, 2006 were as follows:

	Quantity	Maturity		Average Price US$/bbl		Fair Value
Crude Oil and Products *(millions of barrels)*						
Crude oil purchases	2.7	2007	$	63.42	$	(8)
Crude oil sales	2.0	2007	$	61.99	$	6
Buzzard crude oil sales	35.8	2007-2010	$	25.98	$	(1,481)
					$	(1,483)

	Quantity	Maturity		Average Price Cdn$/GJ		Fair Value
Natural Gas*(millions of gigajoules - GJ)*						
Natural gas purchases	1.1	2007	$	7.72	$	(2)
					$	(2)
					$	(1,485)

Note 24 FINANCIAL INSTRUMENTS AND DERIVATIVES *continued*

The fair value of these derivative instruments is based on quotes provided by brokers, which represents an approximation of amounts that would be received or paid to counterparties to settle these instruments prior to maturity. The Company plans to hold all derivative instruments outstanding at December 31, 2006 to maturity.

Derivative and financial instruments involve a degree of credit risk. The Company manages this risk through the establishment of credit policies and limits, which are applied in the selection of counterparties. Market risk relating to changes in value or settlement cost of the Company's derivative instruments is essentially offset by gains or losses on the underlying transaction.

In addition to the derivative instruments described above, the Consolidated Balance Sheet includes other items considered to be financial instruments, such as cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, short-term notes payable and long-term debt. The fair values of these other financial instruments included in the Consolidated Balance Sheet are as follows:

	2006		2005	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Financial instruments included in current assets and current liabilities related to continuing operations	**$ (1,220)**	**$ (1,220)**	$ (557)	$ (557)
Long-term debt	**$ (2,894)**	**$ (2,959)**	$ (2,913)	$ (3,134)

The fair value of financial instruments included in current assets and current liabilities related to continuing operations, excluding the current portion of long-term debt, approximates the carrying amount of these instruments due to their short maturity. The fair value of long-term debt is based on publicly quoted market values.

Note 25 COMMITMENTS AND CONTINGENT LIABILITIES

Commitments

	2007	2008	2009	2010	2011	Thereafter	Total
Transportation agreements	$ 215	$ 213	$ 145	$ 129	$ 109	$ 930	$ 1,741
Exploration work commitments	88	18	18	7	1	-	132
Operating leases	492	140	106	99	75	237	1,149
	$ 795	$ 371	$ 269	$ 235	$ 185	$ 1,167	$ 3,022

Contingent Liabilities

The Company is involved in litigation and claims in the normal course of operations. In addition, the Company may provide indemnifications, in the normal course of operations, that are often standard contractual terms to counterparties in certain transactions, such as purchase and sale agreements. The terms of these indemnifications will vary based upon the contract, the nature of which prevents the Company from making a reasonable estimate of the maximum potential amounts that may be required to be paid. Management is of the opinion that any resulting settlements relating to the litigation matters or indemnifications would not materially affect the financial position or results of operations of the Company.

Note 26 VARIABLE INTEREST ENTITIES

Accounting Guideline 15 (AcG 15), *Consolidation of Variable Interest Entities* (VIEs), provides criteria for the identification of VIEs and further criteria for determining what entity, if any, should consolidate them. Entities in which equity investors do not have the characteristic of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support are subject to consolidation by a company if that company is deemed the primary beneficiary. The primary beneficiary is the party that is subject to a majority of the risk of loss from the VIEs' activities, or is entitled to receive a majority of the VIEs' residual returns, or both. The Company has determined that certain retail licensee and wholesale marketer agreements would constitute VIEs, even though the Company has no ownership in these entities. The Company, however, is not the primary beneficiary and, therefore, consolidation is not required. In certain of the retail licensee arrangements, the Company has provided loan guarantees. Management is of the opinion that the Company's maximum exposure to loss from these arrangements would not be material.

Note 27 GENERALLY ACCEPTED ACCOUNTING PRINCIPLES IN THE UNITED STATES

The application of United States GAAP would have the following effects on earnings as reported:

	Notes	2006	2005	2004
Net earnings from continuing operations, as reported in the Consolidated Statement of Earnings		**$ 1,588**	$ 1,693	$ 1,698
Adjustments, before income taxes				
Accounting for income taxes	(a)	**8**	117	(27)
Capitalization of interest and related amortization	(b)	**47**	46	8
Stock-based compensation	(g)	**(24)**	-	-
Other		-	1	1
Income taxes on above items		**(10)**	(15)	9
Net earnings from continuing operations, as adjusted before cumulative effect of change in accounting policy		**1,609**	1,842	1,689
Net earnings from discontinued operations		**152**	98	59
Net earnings, as adjusted before cumulative effect of change in accounting policy		**1,761**	1,940	1,748
Cumulative effect of change in accounting policy, net of income taxes	(g)	**(14)**	-	-
Net earnings, as adjusted		**$ 1,747**	$ 1,940	$ 1,748
Earnings from continuing operations, as adjusted before cumulative effect of change in accounting policy per share				
Basic		**$ 3.19**	$ 3.55	$ 3.19
Diluted		**$ 3.16**	$ 3.51	$ 3.15
Earnings, as adjusted before cumulative effect of change in accounting policy per share				
Basic		**$ 3.49**	$ 3.74	$ 3.30
Diluted		**$ 3.45**	$ 3.69	$ 3.26
Earnings, as adjusted per share				
Basic		**$ 3.47**	$ 3.74	$ 3.30
Diluted		**$ 3.43**	$ 3.69	$ 3.26
Comprehensive income, net of tax				
Net earnings, as adjusted		**$ 1,747**	$ 1,940	$ 1,748
Unrealized gain (loss) on financial derivatives	(d, f)	-	-	(5)
Change in minimum pension liability	(e, f)	**42**	(65)	(36)
Change in foreign currency translation adjustment	(f)	**369**	(588)	(49)
		$ 2,158	$ 1,287	$ 1,658

Note 27 GENERALLY ACCEPTED ACCOUNTING PRINCIPLES IN THE UNITED STATES *continued*

The application of United States GAAP would have the following effects on the Consolidated Balance Sheet as reported:

	Notes	**December 31, 2006** As Reported	**December 31, 2006** United States GAAP	December 31, 2005 As Reported	December 31, 2005 United States GAAP
Current assets		**$ 2,826**	**$ 2,826**	$ 2,934	$ 2,934
Current assets - discontinued operations		**-**	**-**	237	237
Property, plant and equipment, net	(a, b)	**18,577**	**19,209**	15,921	16,513
Goodwill	(a)	**801**	**780**	737	716
Deferred charges and other assets	(e)	**442**	**314**	415	415
Assets of discontinued operations		**-**	**-**	411	411
Current liabilities	(g)	**3,348**	**3,375**	2,984	2,984
Current liabilities - discontinued operations		**-**	**-**	102	102
Long-term debt		**2,887**	**2,887**	2,906	2,906
Other liabilities	(e, g)	**1,826**	**2,200**	1,888	2,229
Asset retirement obligations		**1,170**	**1,170**	882	882
Future income taxes	(b, e, g)	**2,974**	**2,977**	2,405	2,469
Common shares		**1,366**	**1,366**	1,362	1,362
Contributed surplus	(c)	**469**	**1,591**	1,422	2,544
Retained earnings		**8,557**	**7,831**	7,018	6,285
Foreign currency translation adjustment	(f)	**49**	**-**	(314)	-
Accumulated other comprehensive income (loss)	(e, f)	**$ -**	**$ (268)**	$ -	$ (537)

The Company's Consolidated Financial Statements have been prepared in accordance with Canadian GAAP, which differ in some respects from those applicable in the United States. The following are the significant differences in accounting principles as they pertain to the accompanying Consolidated Financial Statements:

(a) Income Taxes

The liability method followed by the Company differs from United States GAAP due to the application of transitional provisions upon adoption and the use of substantively enacted versus enacted tax rates.

(b) Interest Capitalization

United States GAAP requires that interest be capitalized as part of the cost of certain assets while they are being prepared for their intended use. The Company capitalizes interest attributable to the construction of major new facilities under both Canadian and United States GAAP, but uses different capitalization methodologies under each.

(c) Contributed Surplus

In prior years, the Company transferred amounts from contributed surplus to the accumulated deficit. Under United States GAAP, these transfers are not permitted.

(d) Derivative Instruments and Hedging

United States GAAP requires that changes in the fair value of cash flow hedges be included in other comprehensive income. Under Canadian GAAP, these amounts are recorded in earnings only at the time of settlement.

Note 27 GENERALLY ACCEPTED ACCOUNTING PRINCIPLES IN THE UNITED STATES *continued*

(e) Pensions and Other Post-Retirement Benefits

The Company has adopted Statement of Financial Accounting Standard (SFAS) 158 - *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans - an amendment to SFAS 87, 88, 106, 132(R)*, for United States GAAP for the year ended December 31, 2006. This Statement requires an employer to recognize in its statement of financial position the overfunded or underfunded status of a defined benefit post-retirement plan measured as the difference between the fair value of plan assets and the benefit obligation. The Statement also requires that changes, that would not otherwise be required to be included in period expenses, be recorded initially in other comprehensive income. The Statement has been applied prospectively, with no adjustment to prior periods. As a result, deferred charges and other assets decreased by $128 million, other liabilities increased by $94 million and accumulated other comprehensive income decreased by $142 million, net of taxes of $80 million.

Prior to the adoption of SFAS 158, United States GAAP required that a minimum liability be recorded for underfunded pension plans. The change in the liability, representing the excess of unfunded accumulated benefit obligations over previously unrecognized prior service costs, net of any tax benefits, was recognized in other comprehensive income.

(f) Comprehensive Income

United States GAAP uses the concept of comprehensive income, which includes net earnings and other comprehensive income. The concept of comprehensive income does not yet exist under Canadian GAAP. Other comprehensive income represents the change in equity during the period from transactions and other events from non-owner sources and includes such items as changes in the fair value of cash flow hedges, minimum pension liability adjustments and certain foreign currency translation adjustments.

(g) Stock-Based Compensation

The Company has adopted Statement of Financial Accounting Standard (SFAS) 123(R) *Share-Based Payment* for United States GAAP for the year ended December 31, 2006. This Statement requires compensation costs related to share-based awards classified as liabilities to be recognized as an expense at fair value with re-measurement to fair value each period. Under Canadian GAAP, the Company recognizes compensation cost for stock options, which provide the holder the right to exercise the stock option or surrender the option for cash payment based on the intrinsic value at each period end. This Statement was applied using the modified-prospective basis with no adjustment to prior periods. As a result, current liabilities increased by $27 million, other liabilities increased by $19 million and retained earnings decreased by $29 million, net of taxes of $17 million.

Note 28 RECENT ACCOUNTING PRONOUNCEMENTS

Canadian

Convergence of Canadian GAAP with International Financial Reporting Standards

In 2006, Canada's Accounting Standards Board (AcSB) ratified a strategic plan that will result in Canadian GAAP, as used by public companies, being converged with International Financial Reporting Standards over a transitional period. The AcSB is expected to develop and publish a detailed implementation plan, with a transition period expected to be approximately five years. This convergence initiative is in its early stages as of the date of these annual Consolidated Financial Statements and the Company has the option to adopt United States GAAP at any time prior to the expected conversion date. Accordingly, it would be premature to assess the impact of the initiative, if any, on the Company at this time.

Financial Instruments, Comprehensive Income and Hedges

The AcSB has issued five new accounting standards relating to the recognition, measurement, disclosure and presentation of financial instruments. The new standards comprise five handbook sections:

CICA Section 3855 - *Financial Instruments - Recognition and Measurement*

This standard establishes the criteria for recognizing and measuring financial assets, financial liabilities and non-financial derivatives. It also specifies how financial instrument gains and losses are to be presented. Financial liabilities will be classified as either held-for-trading or other. Held-for-trading instruments will be recorded at fair value with realized and unrealized gains and losses reported in net income. Other instruments will be accounted for at amortized cost with gains and losses reported in net income in the period that the liability is derecognized.

Derivatives will be classified as held-for-trading unless designated as hedging instruments. All derivatives, including embedded derivatives that must be separately accounted for, will be recorded at fair value on the balance sheet. For derivatives that hedge the changes in fair value of an asset or liability, changes in the derivatives' fair value will be reported in net income and be substantially offset by changes in the fair value of the hedged asset or liability attributable to the risk being hedged. For derivatives that hedge variability in cash flows, the effective portion of the changes in the derivatives' fair value will be initially recognized in other comprehensive income and the ineffective portion will be recorded in net income. The amounts temporarily recorded in other comprehensive income will subsequently be reclassified to net income in the periods when net income is affected by the variability in the cash flows of the hedged item.

CICA Section 3865 - *Hedges*

This standard provides optional alternative treatment to Section 3855 for entities which choose to designate qualifying transactions as hedges for accounting purposes. It will replace Accounting Guideline 13 (AcG 13) - *Hedging Relationships*, and build on Section 1651 - *Foreign Currency Translation*, by specifying how hedge accounting is applied and what disclosures are necessary when it is applied. Retroactive application of this section is not permitted.

CICA Section 1530 - *Comprehensive Income*

This standard introduces a new requirement to temporarily present certain gains and losses as part of a new earnings measurement called comprehensive income.

CICA Section 3862 - *Financial Instruments - Disclosures*

This standard requires entities to provide disclosures in their financial statements that enable users to evaluate the significance of financial instruments to the entity's financial position and performance. It also requires that entities disclose the nature and extent of risks arising from financial instruments and how the entity manages those risks.

CICA Section 3863 - *Financial Instruments - Presentation*

This standard establishes standards for presentation of financial instruments and non-financial derivatives and deals with the classification of financial instruments, from the perspective of the issuer, between liabilities and equity, the classification of related interest, dividends, losses and gains, and the circumstances in which financial assets and financial liabilities are offset.

CICA sections 3855, 3865 and 1530 are effective for annual and interim periods in fiscal years beginning on or after October 1, 2006. A presentation reclassification of amounts previously recorded in "Foreign currency translation adjustment" to "Accumulated other comprehensive income" will be made upon adoption of Section 1530. The Company does not expect there to be any other material impact on the Consolidated Financial Statements upon adoption of the new standards.

CICA sections 3862 and 3863 are effective for annual and interim periods beginning on or after October 1, 2007.

Accounting Changes

The AcSB issued CICA Section 1506, *Accounting Changes*. The standard prescribes the criteria for changing accounting policies, together with the accounting treatment and disclosure of changes in accounting policies and estimates, and correction of errors. The standard requires the retrospective application to prior periods' financial statements of changes in accounting principle, unless it is impractical to determine either the period-specific effects or the cumulative effect of the change. Application is on a prospective basis and is effective for changes in accounting policies and estimates and correction of errors made in fiscal years beginning on or after January 1, 2007.

Variable Interest Entities

The Emerging Issues Committee (EIC) issued EIC Abstract 163 - *Determining the Variability to be Considered in Applying AcG 15*. This Abstract, which is harmonized with the equivalent United States FASB Staff Position (FSP) FIN 46(R) - 6 - *Determining the Variability to be Considered in Applying FASB Interpretation No. 46(R)*, provides guidance on how an enterprise should determine the variability to be considered in applying *AcG 15 - Consolidation of Variable Interest Entities*. The Abstract is to be applied prospectively to all entities with which an enterprise first becomes involved and to all entities previously required to be analyzed under AcG 15 when a reconsideration event has occurred beginning the first day of the first reporting period beginning on or after January 1, 2007.

Stripping Costs Incurred During Production

The EIC issued EIC Abstract 160 - *Stripping Costs Incurred in the Production Phase of a Mining Operation*. The Abstract provides that stripping costs incurred during production should be accounted for as a variable production cost and included in the costs of inventory extracted during the period unless the stripping activity represents a betterment to the mineral property. In that instance, the portion considered to be a betterment would be capitalized as part of the cost of the mine and amortized using the unit of production method over the reserves that directly benefit from the specific stripping activity. The Abstract may be applied prospectively or retrospectively and is effective for all stripping costs incurred in fiscal periods beginning after July 1, 2006. The Company does not expect there to be any material impact on the Consolidated Financial Statements upon adoption of the Abstract.

United States

Fair Value Measurements

The FASB issued SFAS 157 - *Fair Value Measurements*. The Statement defines fair value, establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. This Statement applies under other accounting pronouncements that require or permit fair value measurements. The Statement is effective for financial statements issued for fiscal years beginning after November 15, 2007. The Company is in the process of assessing the impact of this Statement.

Accounting for Servicing of Financial Assets

The FASB issued SFAS 156 - *Accounting for Servicing of Financial Assets - an amendment of FASB Statement No. 140*. This Statement requires that an entity separately recognize a servicing asset or a servicing liability when it undertakes an obligation to service a financial asset under a servicing contract in certain situations. Such servicing assets or servicing liabilities are required to be initially measured at fair value. The Statement is effective for fiscal years beginning after September 15, 2006. The Company does not expect there to be a material impact on the Consolidated Financial Statements upon adoption of the Statement.

Accounting for Certain Hybrid Financial Instruments

The FASB issued SFAS 155 - *Accounting for Certain Hybrid Financial Instruments*. This Statement amends SFAS 133 on derivatives and hedging and SFAS 140 on transfers and servicing of financial assets and extinguishments of liabilities. The Statement provides a fair value measurement option for certain hybrid financial instruments containing an embedded derivative that would otherwise require bifurcation. The Statement is effective for all instruments acquired, issued or subject to a re-measurement event occurring in years beginning after September 15, 2006. The Company does not expect there to be a material impact on the Consolidated Financial Statements upon adoption of the Statement.

Note 28 RECENT ACCOUNTING PRONOUNCEMENTS *continued*

Accounting for Uncertainty in Income Taxes

The FASB issued FASB Interpretation No. 48 - *Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109*. The Interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The Interpretation requires the Company to determine whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. Only tax positions that meet the more-likely-than-not recognition threshold are measured to determine the amount of benefit to recognize in the financial statements. The tax position is measured at the largest amount of benefit that is greater than 50% likely of being realized upon ultimate settlement. The Interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The Interpretation is effective for fiscal periods beginning after December 15, 2006 and the provisions of the Interpretation must be applied to all tax positions upon initial adoption. The Company is in the process of assessing the impact of this Interpretation.

Sales Taxes

The Emerging Issues Task Force (EITF) issued EITF Abstract *06-3 - How Taxes Collected from Customers and Remitted to Governmental Authorities Should be Presented in the Income Statement (That is Gross versus Net Presentation)*. The Abstract allows an entity to adopt a policy of presenting taxes that are externally imposed on revenue producing transactions on either a gross or net basis, but requires that the entity disclose its accounting policy regarding presentation of such taxes in the notes to the financial statements. The Abstract is effective for fiscal periods beginning after December 15, 2006 and retrospective application is required. The Company does not expect there to be any material impact on the Consolidated Financial Statements upon adoption of the Abstract.

Exhibit 99-2

Legal Notice - Forward-Looking Information

This Financial Report contains forward-looking information. You can usually identify this information by such words as *"plan," "anticipate," "forecast," "believe," "target," "intend," "expect," "estimate," "budget"* or other similar wording suggesting future outcomes or statements about an outlook. We list below examples of references to forward-looking information:

- business strategies and goals
- outlook (including operational updates and strategic milestones)
- future capital, exploration and other expenditures
- future resource purchases and sales
- construction and repair activities
- refinery turnarounds
- anticipated refining margins
- future oil and gas production levels and the sources of their growth
- project development and expansion schedules and results
- future 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 and resources estimates
- royalties and taxes payable
- production life-of-field estimates
- natural gas export capacity
- future financing and capital activities (including purchases of Petro-Canada common shares under the Company's normal course issuer bid (NCIB) program)
- contingent liabilities (including potential exposure to losses related to retail licensee agreements)
- environmental matters
- future regulatory approvals

Such forward-looking information is subject to known and unknown risks and uncertainties. Other factors may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such information. Such factors include, but are not limited to:

- industry capacity
- imprecise reserves estimates of recoverable quantities of oil, natural gas and liquids from resource plays and other sources not currently classified as reserves
- the effects of weather and climate conditions
- the results of exploration and development drilling and related activities
- the ability of suppliers to meet commitments
- decisions or approvals from administrative tribunals
- risks attendant with domestic and international oil and gas operations
- expected rates of return
- general economic, market and business conditions
- competitive action by other companies
- fluctuations in oil and gas prices
- refining and marketing margins
- the ability to produce and transport crude oil and natural gas to markets
- fluctuations in interest rates and foreign currency exchange rates
- actions by governmental authorities, including changes in taxes, royalty rates and resource-use strategies
- changes in environmental and other regulations
- international political events

Many of these and other similar factors are beyond the control of Petro-Canada. Petro-Canada discusses these factors in greater detail in filings with the Canadian provincial securities commissions and the United States (U.S.) Securities and Exchange Commission (SEC).

We caution readers that this list of important factors affecting forward-looking information is not exhaustive. Furthermore, the forward-looking information in this Financial Report is made as of March 1, 2007 and, except as required by applicable law, Petro-Canada does not update it publicly or revise it. This cautionary statement expressly qualifies the forward-looking information in this Financial Report.

Petro-Canada disclosure of reserves

Petro-Canada's qualified reserves evaluators prepare the reserves estimates the Company uses. The Canadian provincial securities commissions do not consider our reserves staff and management as independent of the Company. Petro-Canada has obtained an exemption from certain Canadian reserves disclosure requirements that allows us to make disclosure in accordance with SEC standards. This exemption allows comparisons with U.S. and other international issuers.

As a result, Petro-Canada formally discloses its reserves data and other oil and gas data using U.S. requirements and practices, and these may differ from Canadian domestic standards and practices. Note that when we use the term barrel of oil equivalent (boe) in this Financial Report, it may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet (Mcf) to one barrel (bbl) is based on an energy equivalency conversion method. This method primarily applies at the burner tip and does not represent a value equivalency at the wellhead.

To disclose reserves in SEC filings, oil and gas companies must prove they are economically and legally producible under existing economic and operating conditions. Proof comes from actual production or conclusive formation tests. The use of terms such as *"probable," "possible," "recoverable,"* or *"potential reserves and resources"* in this Financial Report does not meet the SEC guidelines for SEC filings.

The table below describes the industry definitions that we currently use:

Definitions Petro-Canada uses	**Reference**
Proved oil and gas reserves (includes both proved developed and proved undeveloped)	U.S. SEC reserves definition (Accounting Rules Regulation S-X 210.4-10, FASB-69)
Unproved reserves, probable and possible reserves	CIM (Petroleum Society) definitions (Canadian Oil and Gas Evaluation Handbook, Vol. 1 Section 5)

Contingent and prospective resources	Society of Petroleum Engineers, World Petroleum Congress and American Association of Petroleum Geologist definitions (approved February 2000)

There is no certainty that it will be economically viable or technically feasible to produce any portion of the resources. For use in this Financial Report, *"total resources"* means reserves plus resources.

SEC regulations do not define proved reserves from our oil sands mining operations as an oil and gas activity. These reserves are classified as a mining activity and are estimated in accordance with SEC Industry Guide 7. For internal management purposes, we view these reserves and their development as part of our total exploration and production operations.

Throughout this Financial Report, total Company reserves, total Company production, total Company reserves replacement and total Company reserves life index (RLI) are calculated using the sum of oil and gas activities, and oil sands mining activities. Before royalties, oil sands mining 2006 year-end proved reserves were 345 million barrels (MMbbls) and oil sands mining annual 2006 production was 11 MMbbls.

The Strategic Overview Report, published under separate cover, but available at the same time as the Financial Report provides additional detail on the Company's business strategy and progress toward delivering on long-term goals. This Financial Report provides more detail on Petro-Canada's operational and financial capability. The Report to the Community, which the Company publishes in mid-2007, will elaborate on Petro-Canada's commitment to corporate responsibility objectives and performance.

Petro-Canada is one of Canada's largest oil and gas companies, operating in both the upstream and the downstream sectors of the industry in Canada and internationally. The Company creates value by responsibly developing energy resources and providing world class petroleum products and services. Petro-Canada is proud to be a National Partner to the Vancouver 2010 Olympic and Paralympic Winter Games. Petro-Canada's common shares trade on the Toronto Stock Exchange (TSX) under the symbol PCA and on the New York Stock Exchange (NYSE) under the symbol PCZ.

Management's Discussion and Analysis

This Management's Discussion and Analysis (MD&A), dated effective as of February 12, 2007, should be read in conjunction with the audited Consolidated Financial Statements and Notes for the year ended December 31, 2006, included in the 2006 Financial Report and the 2006 Annual Information Form (AIF). Financial data has been prepared in accordance with Canadian generally accepted accounting principles (GAAP), unless otherwise specified. All dollar values are Canadian dollars, unless otherwise indicated. All oil and natural gas production and reserves volumes are stated before deduction of royalties, unless otherwise indicated. Graphs accompanying the text identify the Company's "value drivers," the key measures of performance in each segment of Petro-Canada's business. A glossary of financial terms and ratios can be found on page 92 of this report.

NON-GAAP MEASURES

Cash flow, which is expressed as cash flow from operating activities before changes in non-cash working capital, is used by the Company to analyse operating performance, leverage and liquidity. Operating earnings represent net earnings, excluding gains or losses on foreign currency translation, disposal of assets and unrealized gains or losses on the mark-to-market valuation of the derivative contracts associated with the Buzzard acquisition. Operating earnings are used by the Company to evaluate operating performance. Cash flow and operating earnings 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. For reconciliation of the operating earnings and cash flow amounts to the associated GAAP measures, refer to the tables on pages 12 and 14, respectively, of this MD&A.

Business Environment

The major economic factors influencing Petro-Canada's upstream financial performance include crude oil and natural gas prices, and foreign exchange, particularly the Canadian dollar/U.S. dollar rates. Crude oil and natural gas prices are affected by a number of factors, including supply and demand balance, weather and political events. Factors influencing Downstream financial performance include the level and volatility of crude oil prices, industry refining margins, movements in crude oil price differentials, demand for refined petroleum products and the degree of market competition.

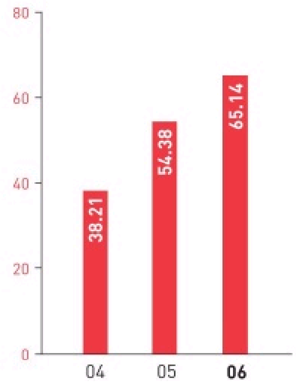
BUSINESS ENVIRONMENT IN 2006

The year 2006 was characterized by volatile crude oil and natural gas prices. The price of North Sea Brent (Dated Brent) moved between highs, in excess of $77 US/bbl, to lows of almost $55 US/bbl. Similarly, benchmark North American natural gas prices at the Henry Hub fluctuated between highs in excess of $10 US/million British thermal units (MMBtu) to lows close to $4 US/MMBtu.

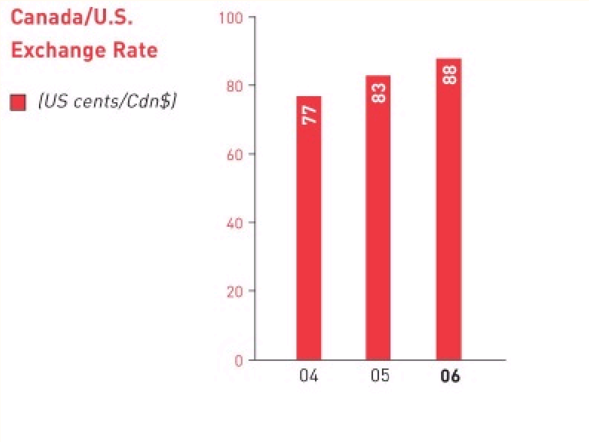
On an annual average basis, the price of Dated Brent reached $65.14 US/bbl, its highest annual average value ever and almost 20% higher than the average in 2005. High oil prices in 2006 were driven by continuing demand growth from China and increased geopolitical tensions globally. Relative to last year, international light/heavy crude (Dated Brent/Mexican Maya) price differentials stabilized in 2006 around the $14 US/bbl level, while Canadian light/heavy crude (Edmonton Light/Western Canada Select (WCS)) spreads narrowed noticeably.

Crude Oil Prices Dated Brent at Sullom Voe

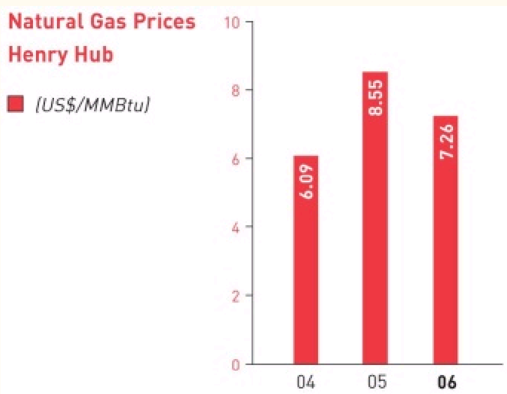
(US$/barrel – bbl)



The continuing appreciation of the Canadian dollar during 2006 reduced the positive impact of higher international prices on Canadian crude prices. The Canadian dollar averaged 88 cents US in 2006, compared with 83 cents US in 2005.



North American natural gas prices suffered a setback during 2006. Record high levels of gas in storage and lower weather-related demand led to significantly lower prices, compared with 2005. Henry Hub prices averaged $7.26 US/MMbtu in 2006, 15% lower than in 2005. Natural gas prices in 2005 reflected the severe impact of hurricanes on U.S. Gulf of Mexico production. In 2006, the Canadian natural gas price at the AECO-C hub fell in line with U.S. prices and averaged almost 18% below its 2005 level.



In the downstream sector, it is estimated that, in 2006, refined petroleum product sales in Canada declined by 1% on top of the 1% reduction in 2005. In spite of lower overall industry product sales and relatively unchanged international light/heavy crude price spreads, overall refining margins increased in 2006, compared with 2005. The impact of the introduction of ultra-low sulphur diesel in the U.S. and Canada effective June 2006 was to maintain heating crack spreads at strong levels. The phasing out of Methyl Tertiary Butyl Ether (MTBE) from gasoline in the U.S. and a heavy refinery turnaround season helped to improve gasoline margins relative to 2005.

Commodity Price Indicators and Exchange Rates

(averages for the years indicated)		**2006**	2005	2004
Crude oil price indicators *(per bbl)*				
Dated Brent at Sullom Voe	**US$**	**65.14**	54.38	38.21
West Texas Intermediate (WTI) at Cushing	**US$**	**66.22**	56.56	41.40
WTI/Dated Brent price differential	**US$**	**1.08**	2.18	3.19
Dated Brent/Mexican Maya price differential	**US$**	**13.94**	13.52	8.20
Edmonton Light	**Cdn$**	**73.23**	69.22	52.78
Edmonton Light/WCS (heavy) price differential	**Cdn$**	**22.40**	25.27	N/A
Natural gas price indicators				
Henry Hub *(per MMBtu)*	**US$**	**7.26**	8.55	6.09
AECO-C spot *(per Mcf)*	**Cdn$**	**7.28**	8.84	7.08
Henry Hub/AECO basis differential *(per MMBtu)*	**US$**	**1.09**	1.53	0.87
New York Harbor 3-2-1 refinery crack spread *(per bbl)*	**US$**	**9.80**	9.47	7.02
US$ per Cdn$ exchange rate	**US$**	**0.88**	0.83	0.77

COMPETITIVE CONDITIONS

It is becoming increasingly challenging for the energy sector to find new sources of oil and gas. Petro-Canada is well positioned to successfully compete for new opportunities that could complement existing upstream resources and increase production of oil and gas. The Company has an estimated 15.9 billion boe of total resources from which to develop new production. Approximately two-thirds of the total resources are located in Alberta's oil sands. As well, with different upstream businesses operating in Canada and internationally, the Company has the flexibility to pursue a wide range of opportunities. While the Company has wide operational scope, it remains a mid-sized global company as measured by production levels. This means Petro-Canada has the operational capability and balance sheet strength to invest in large projects, but smaller acquisitions can also impact the Company's production levels and financial returns.

Petro-Canada is well positioned to compete in the petroleum product refining and marketing business in Canada. The Company accounts for 13% of the total refining capacity in Canada and has a 16% share of the petroleum products market in Canada. Its more than 1,312 retail service station network has the highest gasoline sales per site in Canada among the national integrated oil companies. It also has Canada's largest commercial road transport network, with 219 locations, as well as a robust bulk fuel sales channel.

The Company believes that its strong financial position, combined with a track record of executing large capital projects, and depth of management experience will enable it to continue to compete successfully in the current business environment.

OUTLOOK FOR BUSINESS ENVIRONMENT IN 2007

Prices for energy commodities are expected to remain volatile in 2007, reflecting the unpredictable nature of weather, the level of industry inventories, and political and natural events. High levels of crude oil and refined product inventories, coupled with increased supplies from countries outside of the Organization of the Petroleum Exporting Countries (OPEC), are expected to be more than enough to meet anticipated growth in global oil demand during 2007, thus lessening the upward pressure experienced by oil prices during 2006. The extent of the anticipated price correction will depend on OPEC production adjustments as it tries to mitigate downward price pressures arising from slackened global supply/demand conditions.

Demand growth in North American natural gas markets is expected to be minimal due primarily to lower weather-related demand experienced for most of this heating season. This, combined with high levels of gas in storage, will continue to exert downward pressure on natural gas prices across the continent. The resultant downward pressure on natural gas prices could be partially offset by the challenge to grow production.

In the industry's downstream sector, 2007 refining margins are expected to remain highly volatile and are unlikely to match the high levels experienced in 2006 due to the expectation of slower growth in U.S. and Canadian refined product sales and narrower light/heavy price differentials. The uncertainty arising from continuing changes in the specification for key products, such as motor gasoline and middle distillates, will be a contributing factor to the expected volatility in margins. Also, potential shifts in weather patterns, such as warmer-than-normal temperatures driving down demand for heating fuels or a severe hurricane season that results in damage to key refining centres, could influence refining margins in 2007.

ECONOMIC SENSITIVITIES

The following table shows the estimated after-tax effects that changes in certain factors would have had on Petro-Canada's 2006 net earnings from continuing operations had these changes occurred.

Sensitivities affecting net earnings

Factor[1, 2]	Change (+)	Annual Net Earnings Impact	Annual Net Earnings Impact
		(millions of Canadian dollars)	*($/share)*[3]
Upstream			
Price received for crude oil and liquids[4]	$ 1.00/bbl	$ 39	$ 0.08
Price received for natural gas	$ 0.25/Mcf	32	0.06
Exchange rate: Cdn$/US$ refers to impact on upstream operating earnings from continuing operations[5]	$ 0.01	(33)	(0.07)
Crude oil and liquids production *(barrels per day - b/d)*	1,000 b/d	9	0.02
Natural gas production *(million cubic feet per day - MMcf/d)*	10 MMcf/d	9	0.02
Downstream			
New York Harbor 3-2-1 crack spread	$ 0.10 US/bbl	5	0.01
Light/heavy crude price differential	$ 1.00 US/bbl	6	0.01
Corporate			
Exchange rate: Cdn$/US$ refers to impact of the revaluation of U.S. dollar-denominated, long-term debt[6]	$ 0.01	$ 14	$ 0.03

1 The impact of a change in one factor may be compounded or offset by changes in other factors. This table does not consider the impact of any inter-relationship among the factors.
2 The impact of these factors is illustrative.
3 Per share amounts are based on the number of shares outstanding at December 31, 2006.
4 This sensitivity is based upon an equivalent change in the price of WTI and Dated Brent.
5 A strengthening Canadian dollar versus the U.S. dollar has a negative effect on upstream earnings from continuing operations.
6 A strengthening Canadian dollar versus the U.S. dollar has a positive effect on corporate earnings because the Company holds U.S. denominated debt. The impact refers to gains or losses on $1.4 billion US of the Company's U.S. denominated long-term debt and interest costs on U.S. denominated debt. Gains or losses on $1.1 billion US of the Company's U.S. denominated long-term debt, associated with the self-sustaining International business segment and the U.S. Rockies operations included in the North American Natural Gas business segment, are deferred and included as part of shareholders' equity.

Business Strategy

VALUE PROPOSITION AND STRATEGY

The value proposition Petro-Canada offers to its investors can best be summarized as "Integrated Value from a Diversified Resource Base." The Company's business strategy continues to be:

- improving the profitability of the base business
  - selecting the right assets to develop and then driving for first quartile performance[1]
- taking a disciplined approach to profitable growth
  - leveraging existing assets
  - accessing new opportunities with a focus on long-life assets
  - building a balanced exploration program

Execution of the corporate strategy across all the business units is based on our key beliefs. These influence decisions Petro-Canada makes to deliver value from the integrated portfolio. The Company believes its structure and scope strategically position Petro-Canada to deliver long-term shareholder value. For example, with a base in Canada, Petro-Canada is situated in a stable, resource-rich and demand-driven market. An international presence and integration across businesses provide the Company access to more growth opportunities and an ability to better manage risk. As a mid-sized global company, even smaller sized investments can have a material impact. Last, the Company is committed to developing energy resources responsibly and encouraging opportunities and growth for employees.

EXECUTION OF THE STRATEGY IN 2006

IMPROVING BASE BUSINESS PROFITABILITY

The cornerstone of improving the profitability of the base business is delivering operational excellence. Petro-Canada expects its operated and non-operated facilities to run with high reliability and prudently managed costs. These measures are constantly tracked, reported and improved upon.

- In East Coast Oil, the partner-operated platforms at Hibernia and White Rose had solid operational performance in 2006. Petro-Canada operated Terra Nova had a challenging year when a planned maintenance turnaround was advanced and the turnaround to complete regulatory inspections and reliability improvements was extended. In November, oil production from the Terra Nova field resumed and the Company is targeting to achieve reliability[2] above 90% over time.
- In North American Natural Gas, Western Canada natural gas processing facilities operated at reliability rates greater than 98%. In 2006, the business continued to be faced with industry-wide cost pressures.
- In Oil Sands, the MacKay River *in situ* plant operated at more than 92% reliability. The independently operated Syncrude facility had varying reliability performance through the year, experiencing some delays bringing on the Stage III expansion mid-year, but providing increased production for the last four months of the year.
- The International business unit's production from Northwest Europe exceeded expectations, led by high reliability and the early ramp up to full production of the De Ruyter field. This strong performance was partially offset by lower reservoir performance in Libya and Train 4 startup problems in Trinidad and Tobago.
- In the Downstream, solid operations at the Edmonton and Montreal refineries resulted in a combined reliability index of 95. The Company completed its ultra-low sulphur diesel projects at its Edmonton and Montreal refineries, thereby providing cleaner burning fuels to consumers. A fire at the lubricants plant early in the year was a setback; however, the facility operated with solid reliability for the remainder of the year.
- Corporate wide, the Company views safety and environmental performance as an indicator of operational excellence. In 2006, total recordable injury frequency (TRIF) was reduced by 25% and environmental exceedances were lowered by more than 20%, compared with 2005.

1 References to first quartile operations in this report do not refer to industry-wide benchmarks or externally known measures. The Company has a variety of internal metrics that define and track first quartile operational performance.

2 Throughout this MD&A, the Company refers to reliability within the five business units. These reliability rates are calculated using internal methods that vary among the business units and take various factors into account. There are no existing external or industry-wide standards used in calculating reliability rates and, therefore, resulting calculations are not necessarily comparable to other companies in the oil and gas industry.

LONG-TERM PROFITABLE GROWTH

The Company recognizes that adding new material opportunities is fundamental to long-term growth. Petro-Canada is seeking to increase the relative proportion of long-life resources in the portfolio as a means to deliver sustainable cash flow and earnings. In addition to bringing major projects on-stream, the Company is creating value through its balanced exploration program and business development opportunities.

- In East Coast Oil, discoveries were made in the west and southwest sections of the White Rose field in 2006. Petro-Canada and its partners suspended negotiations with the Government of Newfoundland and Labrador on the Hebron development; however, Petro-Canada continues to consider Hebron a quality asset. At Hibernia, government approval of the development plans for the Southern Extension were not received in 2006, limiting additional production in 2007.
- In North American Natural Gas, the business continued to focus on optimizing the Company's conventional assets and on the transition to unconventional production in Western Canada and the U.S. Rockies. Water treatment permits for wells in the U.S. Rockies were approved, permitting the ramp up of coal de-watering. While the Company is optimistic about its coal bed methane (CBM) opportunities in the U.S. Rockies, it also plans to bring on additional tight gas in areas like the Denver-Julesberg Basin. Progress was also made on the longer term strategy of accessing new supplies, with the addition of acreage in Alaska and advancement of the proposed Gros-Cacouna re-gasification project.
- In Oil Sands, Petro-Canada advanced the Fort Hills project with the filing of a regulatory application to construct and operate the Sturgeon Upgrader near Edmonton. MacKay River production capacity was increased with the addition of a third well pad. The Company also increased *in situ* oil sands landholdings with the purchase of additional leases adjacent to MacKay River.
- In International, Petro-Canada completed the sale of the Company's mature, high-decline producing assets in Syria. Later in the year, the Company completed an agreement to purchase a 90% interest in the Ash Shaer and Cherrife natural gas fields in central Syria, with future plans to build and operate a long-life natural gas development. In the Netherlands sector of the North Sea, the Company-operated De Ruyter project achieved first oil in September, while L5b-C achieved first natural gas in November. In September 2006, the Company furthered its balanced exploration program by securing drilling rigs for its 2007 and 2008 well programs. As well, exploration acreage was added in Libya and the North Sea in 2006. In the United Kingdom (U.K.) sector of the North Sea, the Buzzard project achieved first oil in early 2007. The field is expected to ramp up to full production in mid-2007.
- In the Downstream, capacity at the lubricants plant was expanded by 25% in 2006. Construction to convert the Edmonton refinery to process 100% bitumen-based feedstock commenced and, by year end, 18% of the project was completed. The Downstream also furthered work to evaluate the feasibility of adding a coker to the Montreal refinery.

BUSINESS STRATEGY LOOKING FORWARD

Ensuring existing facilities run safely, reliably and efficiently through excellent execution will continue to be a key focus for Petro-Canada. This same focus on execution will apply to the advancement of major projects. Business plans see the Company adding five major projects over the next several years. Most of these are long-life projects with stable production for 10 years or more. The Buzzard project will ramp up in 2007 and the Edmonton refinery conversion project has been sanctioned and is under construction, with expected completion in 2008. The subsequent projects, shown in the table, are expected to be sanctioned once sufficient front-end engineering work has been completed. Capital expenditures are expected to increase to between $4 billion and $5 billion per year for the next several years, reflecting spending on these major projects.

Major Projects	TARGET ON-STREAM DATE
Buzzard	2007
Edmonton Refinery Conversion	2008
Montreal Refinery Coker	2009
Syria Gas Development	2010
MacKay River Expansion	2010
Fort Hills – Phase 1	2011

As a result of the Company having such a strong suite of projects, Petro-Canada will further focus its portfolio in 2007 to those projects and areas that can make a material difference, that balance the Company's risk profile and that can be executed effectively. As a result, the Company may divest smaller assets and interests in 2007.

Risk Management

PETRO-CANADA'S RISK PROFILE

Petro-Canada's results are impacted by risk and management's strategy for handling risks. Petro-Canada characterizes and manages risks in four broad categories: business risks, market risks, operational risks and foreign risks. Within these categories, risks are listed in alphabetical order below. 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.[1] The following describes Petro-Canada's approach to managing major risks.

BUSINESS RISKS

Counterparties

Petro-Canada is exposed to credit risk due to the uncertainty of business partners' or counterparties' ability to fulfil their obligations. The Company has 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.

Environmental Regulations

Petro-Canada has always been subject to the impact of changing environmental regulations on its operations; however, the risk is considered to be increasing as related laws and regulations become more stringent in Canada and in other countries where Petro-Canada operates. Petro-Canada invests capital to satisfy new product specifications and/or address environmental issues. In 2007, the Company anticipates that it will invest $100 million of its capital expenditure program toward regulatory compliance. As well, the Company conducts Life-Cycle Value Assessments (LCVA), a system to integrate and balance environmental, social and economic decisions for major projects. This process encourages the exploration of alternatives when considering the life-cycle of an asset or product from construction through to abandonment. The LCVA is a useful technique, but it cannot predict changes in environmental regulations. As a result, changes in environmental regulations may impact Petro-Canada's business results.

The Kyoto Protocol, effective in Canada since 2005, requires signatory nations to reduce their emissions of carbon dioxide and other greenhouse gases. The details of implementation of the Protocol in Canada have not been finalized. Depending on the specifics of the regulations, Petro-Canada may be required to reduce emissions of greenhouse gases from operations, to purchase emission-trading credits or pay for other types of offsets. The impact on Petro-Canada could result in substantially higher capital expenditures and/or 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 industry-wide margins for refined products. Through industry organizations, Petro-Canada works with a number of regulatory groups and government associations to find an approach that will minimize the negative financial impact of the greenhouse gas emission regulations on the Company, while still reducing emissions. The level of influence these 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 the contracting of exploration and production interests, impose specific drilling obligations, and expropriate or cancel contract rights. Governments may also regulate prices of commodities or refined products, or intervene indirectly on prices through taxes, royalties and exploration rights.

Petro-Canada tries to mitigate the potentially disruptive impact of government regulations by selecting operating environments with stable governments and by maintaining respectful relationships with governments and regulators. Contact with regulators and governments usually occurs through the Company's management and/or regulatory affairs and government relations personnel. 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 where it operates. By virtue of Petro-Canada's integrated portfolio of businesses, the Company 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 that may have a material adverse effect on the Company.

1 Further detail regarding the Audit, Finance and Risk Committee can be found in the AIF along with a copy of its Charter, attached as Schedule C.

Licence to Operate

Petro-Canada's oil and gas production and refining operations impact communities and surrounding environments. Those impacted can become concerned over the use of scarce resources, such as land and water, the perceived or real threat to human health, the potential impact on biodiversity, and/or possible societal changes to surrounding communities. Petro-Canada must secure and maintain formal regulatory approvals and licences to conduct its operations. In addition, broader societal acceptance of the Company's activities is necessary for resource development. An inability for Petro-Canada to secure local community support, necessary regulatory approvals and licences, and broader societal acceptance can result in projects being delayed or stopped, increasing project costs and damage to the Company's reputation. Lack of local community and stakeholder support can also lead to pressure to limit or shut down operations.

Petro-Canada manages this risk by applying a set of Principles for Responsible Investment and Operations to its businesses. These Principles provide a framework whereby Petro-Canada's operations around the world are conducted in a manner that is economically rewarding to all parties and recognized as being ethically, environmentally and socially responsible. These Principles and the Company's activities in support of them can be found on Petro-Canada's website at www.petro-canada.ca. Even though Petro-Canada is committed to following its Principles and respecting two-way dialogue with applicable stakeholders, there is no guarantee the Company will be granted the licences needed to operate projects within expected timelines or that its reputation with affected stakeholders will not be damaged.

Non-Operated Interests

Petro-Canada has a significant interest in assets where the management of construction or operation is done by other companies. 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% interest) and Buzzard (29.9% interest). Joint venture executive committees manage major projects, so Petro-Canada does have some ability to influence these projects. As well, Petro-Canada has joint venture or other operating agreements, which specify the Company's expectations from third-party operators. Nevertheless, third-party operation and management of the Company's assets could adversely affect Petro-Canada's financial performance.

Project Execution

Petro-Canada manages a variety of projects to support continuing operations and future growth. Petro-Canada's goal is to consistently deliver projects in alignment with expectations. Project execution risks include, but are not limited to, changes in project scope, labour availability and productivity, material and services availability and costs, design and construction errors, regulatory approvals, project management and operational capability. To mitigate these risks, Petro-Canada applies a project delivery management system, establishes strong project management teams, breaks large projects down into manageable components, builds on experience and existing technologies, works with all stakeholders on safety and environmental expectations, and conducts post-project reviews to improve project management and operational capabilities. Petro-Canada primarily delivers projects through engineering, procurement and construction (EPC) companies. Through the establishment of strong, internal project management teams, the Company establishes effective working relationships with EPC companies.

In 2006, Petro-Canada completed a number of projects, including converting refineries to produce cleaner burning fuels, expansion of the lubricants plant and bringing the Company-operated De Ruyter project in the North Sea on-stream. These projects represented $1.7 billion of investment, which was completed on time and on budget. Nevertheless, the inability of Petro-Canada to execute projects as expected is a risk to the Company. Globally, there is a focus on execution and projects are tending to be larger and more complex at the same time as the pool of experienced personnel is declining. The Company has recognized the need to provide the organizational capability to successfully execute these projects and, as such has been building its capabilities through recruiting and internal training; however, the inability to adequately source the staffing requirements could jeopardize successful project execution.

Reserves Estimates

Estimates of economically recoverable oil and gas reserves are based upon a number of variables and assumptions. These 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 auditor, has tested aspects of the non-engineering control processes Petro-Canada used in establishing reserves. As well, independent engineering firms assess a significant portion of 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 reserves booking practices can be found in the Company's AIF.

Reserves Replacement [1,2]

Petro-Canada's future cash flows from continuing operations are highly dependent on its ability to offset natural declines as reserves are produced. As basins mature, replacement of reserves becomes more challenging and expensive. In some geographic areas, the Company may choose to allow its reserves to decline if replacement is uneconomical, pursuing other reserves additions instead from successful exploration or acquisitions.

Petro-Canada's reserves objective is to fully replace proved reserves over a five-year period. In 2006, the Company replaced 134% of its production on a proved reserves basis, compared with 111% in 2005. The Company's five-year proved replacement ratio was 160% at year-end 2006. There is no assurance Petro-Canada will successfully replace reserves that are produced in any given year.

MARKET RISKS

More detailed quantification of the impact of some of the following risks can be found in the earnings sensitivities table on page 5 of the Business Environment section in the MD&A.

Commodity Prices

The prices of crude oil and natural gas fluctuate in response to market factors that are external to Petro-Canada. Commodity prices are volatile and influenced by factors such as supply and demand fundamentals, geopolitical events, OPEC decisions and weather. For historical commodity prices, please refer to page 4 of the Business Environment section in the MD&A. Changes in crude oil and natural gas prices affect the price that Petro-Canada receives for its upstream production. Commodity prices also impact the refined product margins realized in the Downstream business. Petro-Canada's ability to maintain product margins in an environment of higher feedstock costs is contingent upon the Company's ability to pass on higher costs 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/or to reduce commodity price risk on specific exposures. Certain Downstream physical transactions are routinely hedged for operational needs and to facilitate sales to customers.

Foreign Exchange

Because energy commodity prices are primarily in U.S. dollars, 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 strategy lets the Company take advantage of lower interest rates on floating debt, while matching overall debt maturities with the life of cash-generating assets. While 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. Periodically, the Company reviews the proportion of fixed to floating rate debt issued.

1 See legal notice on page 2 regarding oil and gas, and oil sands mining activities.
2 Proved reserves replacement ratio is calculated by dividing the year-over-year net change in proved reserves, before deducting production, by the annual production over the same period. The reserves replacement ratio is a general indicator of the Company's reserves growth. It is only one of a number of metrics that can be used to analyse a company's upstream business.

Derivative Instruments

Petro-Canada has a formal policy that prohibits the use of derivative instruments for speculative purposes. All derivative instruments entered into are for the purpose of mitigating identified price risks.

Petro-Canada continually monitors outstanding derivative instruments. This includes an assessment of fair values of all derivative instruments using independent third-party quotes to determine the value of each derivative instrument. The objectives of all price risk mitigation transactions are documented, and the effectiveness of each derivative instrument in offsetting the identified price risk is periodically assessed. Petro-Canada also limits the transaction term of its derivative instruments.

The Company applied mark-to-market accounting treatment to all derivative transactions that it entered into in 2006. Realized and unrealized gains and losses resulting from changes in the fair value of derivative instruments that do not qualify for hedge accounting are recognized in "Investment and Other Income." For derivative instruments that qualify for hedge accounting, Petro-Canada may elect to apply hedge accounting treatment.

During 2004, 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 Dated Brent crude oil. The purpose of these transactions was to ensure value-added 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 bbls. This volume represents approximately 50% of the Company's share of estimated plateau production from July 1, 2007 to December 31, 2010. As at December 31, 2006, the Buzzard derivative instruments had a recognized mark-to-market unrealized loss of $1,007 million after-tax, of which $240 million was recognized in the income statement in 2006.

In 2006, other derivative instruments in place for refining supply and product purchases resulted in an increase in net earnings from continuing operations of about $1 million after-tax, compared with an increase of about $4 million in 2005.

OPERATIONAL RISKS

Exploring for, developing, producing, refining, transporting and marketing oil, natural gas and refined products involve significant operational risks. These risks include situations such as well blowouts, fires, explosions, gaseous leaks, equipment failures, migration of harmful substances and oil spills. Any of these operational incidents, including events beyond the Company's control, could cause personal injury, environmental contamination, interruption of production, and/or damage and destruction of the Company's assets.

Petro-Canada manages operational risks primarily through a Total Loss Management (TLM) system that has standards to prevent losses. Regular TLM audits test compliance with these standards. The Company also has a Zero-Harm philosophy, a belief that injuries and illnesses, on and off the job, are foreseeable and preventable.

The Company also purchases insurance to transfer the financial impact of some operational risks to third-party insurers. On an annual basis, Petro-Canada management evaluates its operational risk exposures and adjusts its insurance coverage, including deductibles and limits. While Petro-Canada maintains insurance consistent with industry practices, the Company cannot and does not fully insure against all risks. Losses resulting from operational incidents could have an adverse impact on the Company.

Interruption to production at any one of Petro-Canada's facilities could result in an adverse financial impact; however, the risk of multiple facilities experiencing production interruptions at the same time is mitigated by having multiple large producing and upgrading assets in various geographic locations throughout the world.

FOREIGN RISKS

Petro-Canada has significant operations 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 of actions by governmental authorities, internal unrest, war, political disruption, economic and legal sanctions (such as restrictions against countries that the U.S. government may deem to sponsor terrorism), and changes in global trade policies. The Company's operations may be restricted, disrupted or prohibited in any country in which these risks occur. Petro-Canada also has production in countries that are members of OPEC, which has resulted in, and may result in, the future for production volumes to be constrained by quotas.

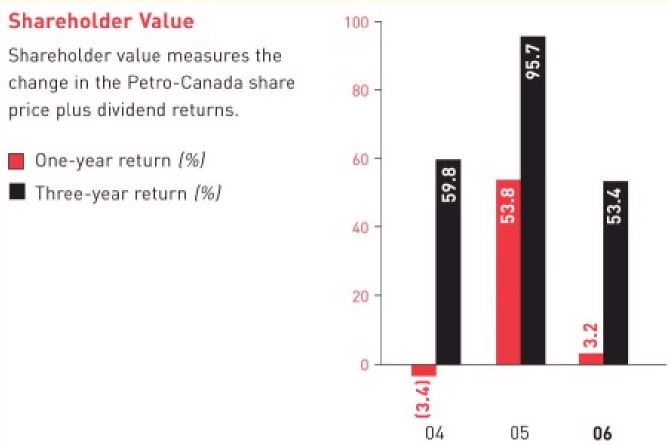
The Company continually evaluates exposure in any one country in the context of total operations. Investment may be limited to avoid excessive exposure in any one country or region. The Company also purchases political risk insurance to partially mitigate certain political risks.

Consolidated Financial Results

ANALYSIS OF CONSOLIDATED EARNINGS AND CASH FLOW

Consolidated Financial Results

On January 31, 2006, Petro-Canada closed the sale of the Company's producing assets in Syria. These assets and associated results are reported as discontinued operations and are excluded from continuing operations.



(millions of Canadian dollars, unless otherwise indicated)			**2006**		2005		2004
Net earnings		**$**	**1,740**	**$**	**1,791**	**$**	**1,757**
Net earnings from discontinued operations			**152**		98		59
Net earnings from continuing operations		**$**	**1,588**	**$**	**1,693**	**$**	**1,698**
Gain on foreign currency translation [1]			**1**		73		63
Unrealized loss on Buzzard derivative contracts [2]			**(240)**		(562)		(205)
Gain on sale of assets			**25**		34		11
Operating earnings from continuing operations [3, 4]		**$**	**1,802**	**$**	**2,148**	**$**	**1,829**
Stock-based compensation			**(31)**		(66)		(11)
Insurance proceeds (surcharges) [5]			**8**		(75)		31
Income tax adjustments			**(185)**		22		13
Oakville closure costs			**-**		2		(46)
Operating earnings from continuing operations adjusted for unusual items		**$**	**2,010**	**$**	**2,265**	**$**	**1,842**
Earnings per share from continuing operations *(dollars)*	- basic	**$**	**3.15**	$	3.27	$	3.21
	- diluted		**3.11**		3.22		3.17
Earnings per share *(dollars)*	- basic	**$**	**3.45**	$	3.45	$	3.32
	- diluted		**3.41**		3.41		3.28
Cash flow from continuing operating activities before changes in non-cash working capital [4, 6]			**3,687**		3,787		3,425
Cash flow from continuing operating activities before changes in non-cash working capital per share *(dollars)*			**7.32**		7.31		6.47
Debt			**2,894**		2,913		2,580
Cash and cash equivalents [7]			**499**		789		170
Average capital employed [7]		**$**	**12,868**	$	11,860	$	10,533
Return on capital employed *(%)* [7]			**14.3**		16.0		17.5
Operating return on capital employed *(%)* [7]			**15.0**		19.8		18.8
Return on equity *(%)* [7]			**17.5**		19.7		21.5

1 Foreign currency translation reflects gains or losses on U.S. dollar-denominated long-term debt not associated with the self-sustaining International business unit and the U.S. Rockies operations included in the North American Natural Gas business unit.
2 As part of its acquisition of an interest in the Buzzard field in the U.K. sector of the North Sea in June 2004, the Company entered into derivative contracts for half of its share of estimated production for 3½ years, starting July 1, 2007.
3 Operating earnings, which represent net earnings excluding gains or losses on foreign currency translation and on disposal of assets and the unrealized gains or losses associated with the Buzzard derivative contracts, are used by the Company to evaluate operating performance.
4 Operating earnings and cash flow from continuing operations 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.
5 Insurance premium surcharges include accruals and surcharges for Oil Insurance Ltd. (OIL) and sEnergy Insurance Ltd. (sEnergy) policies. OIL is a mutual insurance company that insures against property damage in the energy sector. sEnergy was a mutual insurance company that provided business interruption and excess property insurance to the energy sector.
6 Cash flow, which is expressed before changes in non-cash working capital items relating to operating activities, is used by the Company to analyse operating performance, leverage and liquidity.
7 Includes discontinued operations.

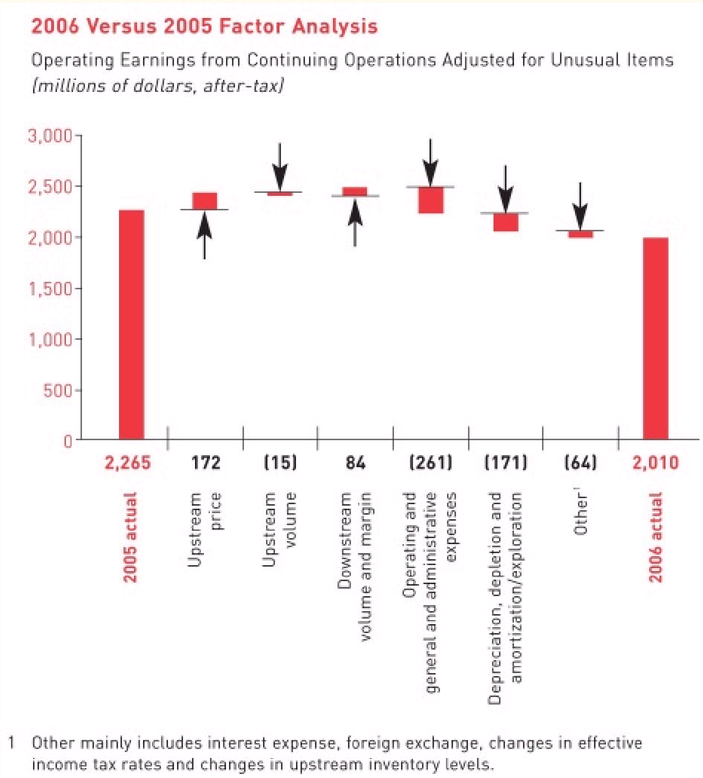
2006 COMPARED WITH 2005

Operating earnings from continuing operations adjusted for unusual items decreased 11% to $2,010 million in 2006, compared with $2,265 million in 2005. Lower upstream production, declining realized natural gas prices and higher operating and exploration costs were partially offset by stronger realized crude oil prices.

In 2006, operating earnings from continuing operations included a number of unusual items: $185 million charge for income tax rate and other tax adjustments, $37 million in insurance proceeds, a $31 million charge related to the mark-to-market of stock-based compensation and a $29 million insurance premium surcharge.

In 2005, operating earnings from continuing operations included a number of unusual items: a $77 million insurance premium surcharge, a $66 million charge related to the mark-to-market of stock-based compensation and a $22 million positive adjustment related to income tax rate and other tax adjustments.

Net earnings from continuing operations in 2006 were $1,588 million, down 6% compared with $1,693 million in 2005, primarily due to lower production, declining realized natural gas prices and income tax adjustments, partially offset by lower realized losses on Buzzard derivative contracts. Net earnings from continuing operations included gains or losses on foreign currency translation, unrealized losses on Buzzard derivative contracts and gains on asset sales.



QUARTERLY INFORMATION

Consolidated Quarterly Financial Results

		2006				2005		
(millions of Canadian dollars, unless otherwise indicated)	**Quarter 1**	**Quarter 2**	**Quarter 3**	**Quarter 4**	Quarter 1	Quarter 2	Quarter 3	Quarter 4
Total revenue from continuing operations	**$ 4,188**	**$ 4,730**	**$ 5,201**	**$ 4,550**	$ 3,275	$ 3,945	$ 4,721	$ 4,838
Operating earnings from continuing operations	**202**	**532**	**597**	**471**	427	476	597	648
Net earnings from continuing operations	**54**	**472**	**678**	**384**	110	322	593	668
Cash flow from continuing operating activities before changes in non-cash working capital	**857**	**754**	**1,085**	**991**	801	869	1,001	1,116
Earnings per share from continuing operations *(dollars)*								
- basic	**$ 0.11**	**$ 0.93**	**$ 1.36**	**$ 0.77**	$ 0.21	$ 0.62	$ 1.14	$ 1.29
- diluted	**$ 0.10**	**$ 0.92**	**$ 1.34**	**$ 0.76**	$ 0.21	$ 0.61	$ 1.13	$ 1.28
Earnings per share *(dollars)*								
- basic	**$ 0.40**	**$ 0.93**	**$ 1.36**	**$ 0.77**	$ 0.23	$ 0.66	$ 1.19	$ 1.38
- diluted	**$ 0.40**	**$ 0.92**	**$ 1.34**	**$ 0.76**	$ 0.22	$ 0.66	$ 1.17	$ 1.36

Revenue and net earnings variances from quarter to quarter resulted mainly from fluctuations in commodity prices and refinery cracking margins, the impact on production and processed volumes from maintenance and other shutdowns at major facilities, and the level of exploration drilling activity. For further analysis of quarterly results, refer to Petro-Canada's quarterly reports to shareholders available on the Company's website at www.petro-canada.ca.

Liquidity and Capital Resources

Summary of Cash Flows

(millions of Canadian dollars)	**2006**	2005	2004
Cash flow from continuing operating activities	**$ 3,608**	$ **3,783**	**$ 3,928**
Increase (decrease) in non-cash working capital related to continuing operating activities and other	**79**	4	(503)
Cash flow from continuing operations	**$ 3,687**	**$ 3,787**	**$ 3,425**
Cash flow from discontinued operating activities	**15**	204	233
Increase (decrease) in non-cash working capital related to discontinued operating activities	**2**	41	(29)
Cash flow	**3,704**	**4,032**	**3,629**
Net cash inflows (outflows) from:			
investing activities before changes in non-cash working capital	**(2,797)**	(3,595)	(4,591)
financing activities before changes in non-cash working capital	**(1,175)**	(10)	(19)
(Increase) decrease in non-cash working capital	**(22)**	192	516
Increase (decrease) in cash and cash equivalents	**$ (290)**	$ 619	$ (465)
Cash and cash equivalents at end of year	**$ 499**	**$ 789**	**$ 170**
Cash and cash equivalents - discontinued operations	**$ -**	**$ 68**	**$ 206**

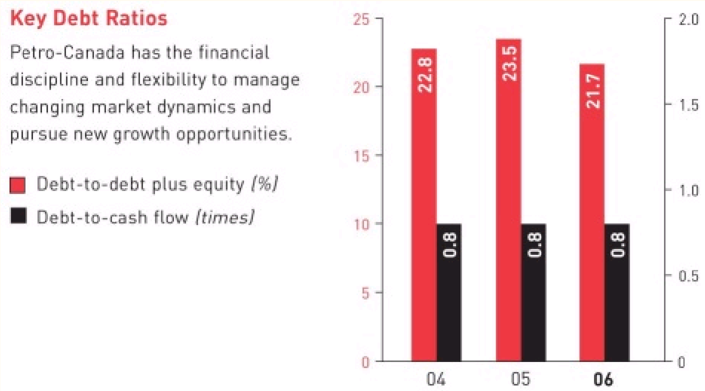
In 2006, cash flow from continuing operations was $3,687 million ($7.32/share), compared with $3,787 million ($7.31/share) in 2005. The decrease in cash flow reflected lower operating earnings from continuing operations.

Financial Ratios

	2006	2005	2004
Interest coverage from continuing operations *(times)*[1]			
Net earnings basis	**19.2**	17.9	20.0
EBITDAX basis	**27.0**	25.4	29.2
Cash flow basis	**27.4**	28.9	30.4
Debt-to-cash flow *(times)*[2]	**0.8**	0.8	0.8
Debt-to-debt plus equity *(%)*	**21.7**	23.5	22.8

1 Refer to the Glossary of Terms and Ratios on page 92 for methods of calculation.
2 From continuing operations.

Petro-Canada's financing strategy is designed to maintain financial strength and flexibility to support profitable growth in all business environments. Two key measures that Petro-Canada uses to measure the Company's overall financial strength are debt-to-cash flow from continuing operations and debt-to-debt plus equity. Petro-Canada's debt-to-cash flow from continuing operations ratio, the key short-term measure, was 0.8 times at December 31, 2006 and 2005. This was well within the Company's target range of no more than 2.0 times. Debt-to-debt plus equity, the long-term measure for capital structure, was 21.7% at year-end 2006, down from 23.5% at year-end 2005. This was below the target range of 25% to 35% for both years, providing the financial flexibility to fund the Company's capital program and profitable growth opportunities. Financial covenants associated with the Company's various debt arrangements are reviewed regularly and controls are in place to ensure compliance with these covenants.



OPERATING ACTIVITIES

Excluding cash and cash equivalents, short-term notes payable and the current portion of long-term debt, the operating working capital deficiency, including discontinued operations, was $1,014 million at December 31, 2006, compared with an operating working capital deficiency, including discontinued operations, of $697 million at December 31, 2005. The working capital deficiency, including discontinued operations, was higher primarily due to a decrease in accounts receivable and an increase in accounts payable.

INVESTING ACTIVITIES

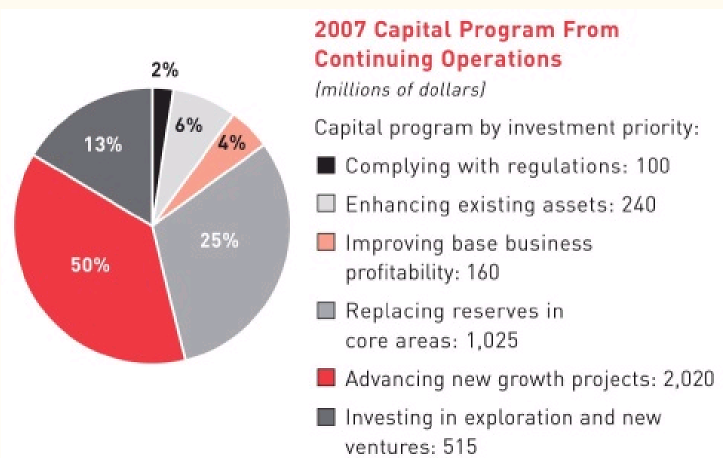
Capital and Exploration Expenditures

(millions of Canadian dollars)		2007 Outlook [1]		**2006**		2005		2004
Upstream								
North American Natural Gas	$	780	**$**	**788**	$	713	$	666
East Coast Oil		210		**256**		314		275
Oil Sands		770		**377**		772		397
International [2]		865		**760**		696		1,707 [3]
	$	**2,625**	**$**	**2,181**	**$**	**2,495**	**$**	**3,045**
Downstream								
Refining and Supply	$	1,215	**$**	**1,038**	$	883	$	656
Sales and Marketing		150		**142**		108		171
Lubricants		25		**49**		62		12
	$	**1,390**	**$**	**1,229**	**$**	**1,053**	**$**	**839**
Shared Services	**$**	**35**	**$**	**24**	**$**	**12**	**$**	**9**
Total property, plant and equipment and exploration	**$**	**4,050**	**$**	**3,434**	**$**	**3,560**	**$**	**3,893**
Deferred charges and other assets		10		**50**		70		36
Acquisition of Prima Energy Corporation		-		**-**		-		644
Total continuing operations	**$**	**4,060**	**$**	**3,484**	**$**	**3,630**	**$**	**4,573**
Discontinued operations	$	-	**$**	**1**	$	46	$	62
Total	**$**	**4,060**	**$**	**3,485**	**$**	**3,676**	**$**	**4,635**

1 The 2007 outlook was previously released on December 14, 2006.
2 International excludes capital expenditures related to the Syrian producing assets, which are reflected as discontinued operations.
3 Includes $1,218 million for the Buzzard acquisition.

Capital and exploration expenditures were $3,485 million in 2006, down 5% compared with $3,676 million in 2005, mainly reflecting lower investment in Oil Sands assets.

In 2007, spending on new growth projects is expected to increase. More than 60% of planned capital expenditures support delivering profitable new growth, and funding exploration and new ventures. This estimate is up from nearly 53% in these categories in 2006. The remaining 40% of the 2007 planned capital expenditures are directed toward replacing reserves in core areas, enhancing existing assets, improving base business profitability and complying with regulations. The regulatory compliance portion of the program was greater in 2006, primarily reflecting expenditures to produce cleaner burning fuels at Downstream refineries.



FINANCING ACTIVITIES AND DIVIDENDS

Sources of Capital Employed

(millions of Canadian dollars)		**2006**		2005		2004
Short-term notes payable	**$**	**-**	$	-	$	299
Long-term debt, including current portion		**2,894**		2,913		2,281
Shareholders' equity		**10,441**		9,488		8,739
Total	**$**	**13,335**	$	12,401	$	11,319

Total debt decreased to $2,894 million at December 31, 2006, compared with $2,913 million at the previous year end. The decrease in debt was due to capital lease repayments made in 2006.

2006 Financing Activities

During the fourth quarter, Petro-Canada increased its syndicated committed credit facilities to $2,200 million from $2,000 million. At December 31, 2006, the Company also had bilateral demand credit facilities of $829 million. A total of $1,444 million of the credit facilities was used for letters of credit and overdraft coverage at December 31, 2006. The syndicated facilities also provide liquidity support to Petro-Canada's commercial paper program. No commercial paper was outstanding at year-end 2006. The Company will continue to use its cash position, draw on bank lines and issue commercial paper or long-term notes as necessary to meet working capital and other financing requirements. Petro-Canada plans to meet remaining debt repayment commitments from a combination of cash flow and debt refinancing.

The Company's unsecured long-term debt securities are rated Baa2 by Moody's Investors Service, BBB by Standard & Poor's and A (low) by Dominion Bond Rating Service. The Company's long-term debt ratings remained unchanged from year-end 2005.

Petro-Canada's short-term debt securities are rated R-1 (low) by Dominion Bond Rating Service. This rating remains unchanged from year-end 2005.

Returning Cash to Shareholders

Petro-Canada's first priority use of cash is to fund its capital program and profitable growth opportunities, and then to look to return cash to shareholders through dividends and a share buyback program.

Petro-Canada regularly reviews its dividend strategy to ensure the alignment of the dividend policy with shareholder expectations, and financial and growth objectives. Consistent with these objectives, on December 14, 2006, the Company declared a 30% increase in its quarterly dividend to $0.13/share, commencing with the dividend payable April 1, 2007. Total dividends paid in 2006 were $201 million, compared with $181 million in 2005.

In 2004, Petro-Canada initiated a NCIB program, which was renewed in 2005 and 2006. The current program, which extends to June 21, 2007, entitles the Company to purchase up to 5% of the outstanding common shares, subject to certain conditions. The level of activity in the NCIB program during the first two quarters of 2006 reflected the use of proceeds from the sale of the mature Syrian assets to buy back shares.

Period	**Shares Repurchased**		**Average Price**		**Total Cost**	
	2006	2005	**2006**	2005	**2006**	2005
Full year	**19,778,400**	8,333,400	**$51.10**	$41.54	**$1,011 million**	$346 million

Off Balance Sheet

The Company has certain retail licensee and wholesale marketing agreements that would constitute variable interest entities as described in Note 26 to the Consolidated Financial Statements. These entities are not consolidated because Petro-Canada is not the primary beneficiary and, therefore, consolidation is not required. The Company's maximum exposure to losses from these arrangements would not be material. Other off balance sheet activities are limited to the accounts receivable securitization program, which does not meet the criteria for consolidation and guarantees.

Pension Plans

At year-end 2006, Petro-Canada's defined benefit pension plans were underfunded by $300 million, compared with an underfunded position of $378 million at year-end 2005. For both the defined benefit and defined contribution pension plans, the Company made cash contributions of $114 million and recorded a pension expense of $91 million before-tax in 2006. This compares with $112 million of cash contributions and $78 million before-tax of pension expense in 2005. The Company expects to make pension contributions of approximately $115 million in 2007.

Contractual Obligations - Summary

		PAYMENTS DUE BY PERIOD			
(millions of Canadian dollars)	**Total**	2007	2008-2009	2010-2011	2012 and thereafter
Unsecured debentures and senior notes [1]	**$ 6,260**	$ 175	$ 351	$ 351	$ 5,383
Capital lease obligations [1]	**142**	15	21	21	85
Operating leases	**1,149**	492	246	174	237
Transportation agreements	**1,741**	215	358	238	930
Product purchase/delivery obligations [2]	**2,539**	280	375	275	1,609
Exploration work commitments [3]	**132**	88	36	8	-
Asset retirement obligations	**3,481**	67	106	126	3,182
Other long-term obligations [4, 5]	**2,756**	197	853	393	1,313
Total contractual obligations	**$ 18,200**	$ 1,529	$ 2,346	$ 1,586	$ 12,739

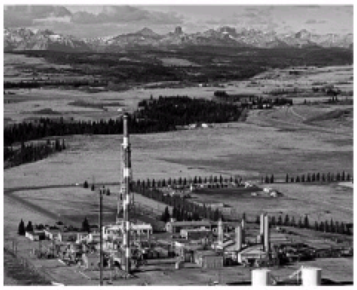
1 Obligations include related interest. For further details, see Note 18 to the 2006 Consolidated Financial Statements.
2 Excludes supply purchase agreements contracted at market prices of $11,400 million, where the products could reasonably be re-sold into the market.
3 Excludes other amounts related to the Company's expected future capital spending. Capital spending plans are reviewed and revised annually to reflect Petro-Canada's strategy, operating performance and economic conditions. For further information regarding future capital spending plans, refer to the business segment and investing activities discussions of the 2006 MD&A.
4 Includes processing agreement with Suncor Energy Inc., receivables securitization program, pension funding obligations for the periods prior to the Company's next required pension plan valuation and other obligations. Pension obligations beyond the next required pension valuation date were excluded due to the uncertainty as to the amount or timing of these obligations.
5 Petro-Canada is involved in litigation and claims associated with normal operations. Management is of the opinion that any resulting settlements would not materially affect the financial position of the Company. The table excludes amounts for these contingencies due to the uncertainty as to the amount or timing of any settlements.

During 2006, Petro-Canada's total contractual obligations increased by approximately $1.5 billion, mainly due to an increase in the estimate of asset retirement obligations, additional product purchase obligations and operating lease commitments.

Upstream

Petro-Canada's upstream operations consisted of four business segments in 2006: 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 Northeast Alberta; and International, where the Company is active in three core areas: Northwest Europe, North Africa/Near East and Northern Latin America.

The diverse asset base provides a balanced portfolio and a platform for long-term growth. In 2007, Petro-Canada is consolidating its East Coast Oil and International businesses. The purpose of the consolidation is to leverage and grow the capabilities of similar operations.



Wildcat Hills gas plant in Alberta

Terra Nova Floating Production Storage and Offloading (FPSO) vessel in Newfoundland and Labrador

MacKay River *in situ* oil sands plant in northern Alberta

De Ruyter platform in the North Sea

NORTH AMERICAN NATURAL GAS

BUSINESS SUMMARY AND STRATEGY

North American Natural Gas explores for and produces natural gas and crude oil and natural gas liquids (NGL) in Western Canada and the U.S. Rockies. This business also markets natural gas in North America and has established resources in the Mackenzie Delta/Corridor and Alaska.

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

- targeting 75% to 80% reserves replacement
- transitioning further into unconventional gas plays
- optimizing core properties in Western Canada and developing CBM and tight gas in the U.S. Rockies
- increasing the focus on exploration
- developing liquefied natural gas (LNG) import capacity at Gros-Cacouna, Quebec
- building the northern resource base for long-term growth

North American Natural Gas Financial Results

(millions of Canadian dollars)		**2006**		2005		2004
Net earnings	**$**	**405**	**$**	**674**	**$**	**500**
Gain on sale of assets		**3**		14		-
Operating earnings	**$**	**402**	**$**	**660**	**$**	**500**
Insurance premium surcharges		**(1)**		(4)		-
Income tax adjustments		**6**		28		7
Operating earnings adjusted for unusual items	**$**	**397**	**$**	**636**	**$**	**493**
Cash flow from operating activities before changes in non-cash working capital	**$**	**739**	$	1,193	$	882
Expenditures on property, plant and equipment and exploration	**$**	**788**	$	713	$	666
Total assets	**$**	**4,151**	$	3,763	$	3,477

2006 COMPARED WITH 2005

North American Natural Gas contributed $397 million of operating earnings adjusted for unusual items, down considerably from $636 million in 2005. Weak natural gas prices, lower Western Canada production, increased operating costs, higher exploration expenses and higher depreciation, depletion and amortization were partially offset by higher U.S. Rockies production.

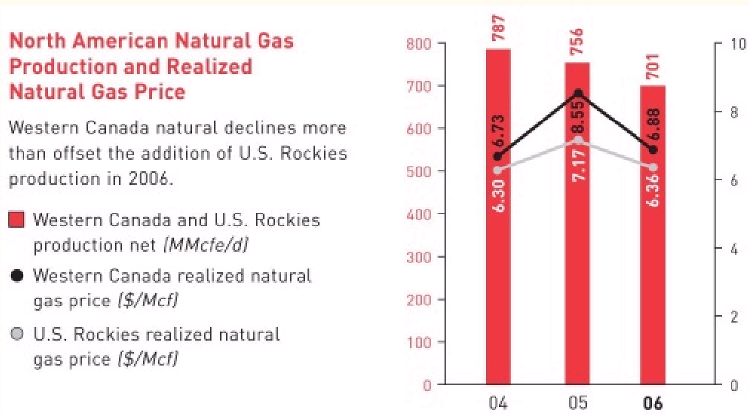
Net earnings for North American Natural Gas were $405 million in 2006, down from $674 million in 2005. Net earnings in 2006 included a $6 million income tax adjustment, a $3 million gain on sale of assets and a $1 million insurance premium surcharge. Net earnings in 2005 included a $14 million gain on sale of assets, a $4 million insurance premium surcharge and a $28 million positive adjustment to income tax rate and other tax adjustments.

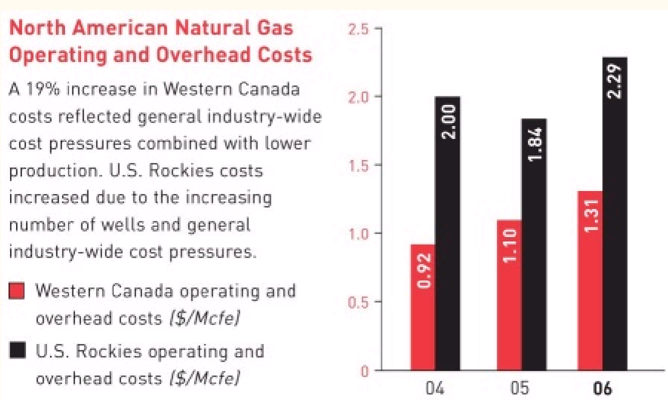
Oil and natural gas production averaged 701 million cubic feet/day of natural gas equivalent (MMcfe/d) in 2006, down from 756 MMcfe/d in 2005, as natural declines in Western Canada were partially offset by U.S. Rockies production growth. Natural gas commodity prices declined in 2006. The North American realized natural gas price averaged $6.85/Mcf in 2006, down 19% from $8.47/Mcf in 2005.

2006 OPERATING REVIEW AND STRATEGIC INITIATIVES

The North American Natural Gas business is positioning for the future with an increased focus on unconventional gas plays, acquisition of land in the Far North and progress on the proposed Quebec LNG project.

2006 Operating Review





		2006		2005		2004
Production net *(MMcfe/d)*						
Western Canada		**646**		704		764
U.S. Rockies		**55**		52		23 [1]
Total North American Natural Gas production net		**701**		756		787
Western Canada realized natural gas price *($/Mcf)*	**$**	**6.88**	$	8.55	$	6.73
U.S. Rockies realized natural gas price *($/Mcf)*	**$**	**6.36**	$	7.17	$	6.30
Western Canada operating and overhead costs *($/Mcfe)*	**$**	**1.31**	$	1.10	$	0.92
U.S. Rockies operating and overhead costs (*$/Mcfe*)	**$**	**2.29**	$	1.84	$	2.00

1 U.S. Rockies production in 2004 is from the date of acquisition in July 2004.

Western Canada

Western Canada natural gas production averaged 646 MMcfe/d in 2006, down 8% from 704 MMcfe/d in 2005. Exploration and development drilling activity in Western Canada resulted in 393 successful wells (gross), for an overall success rate of 93% in 2006. Western Canada operating and overhead costs were $1.31/Mcfe in 2006, up from $1.10/Mcfe in the previous year. The operating and overhead cost increase in Western Canada reflected general industry-wide cost pressures for materials, fuel and labour, combined with lower production.

U.S. Rockies

U.S. Rockies natural gas production averaged 55 MMcfe/d in 2006, up 6% from 52 MMcfe/d in 2005. The increase reflected natural gas breakthrough at the Wild Turkey CBM field. Exploration and development drilling activity in the U.S. Rockies during 2006 resulted in more than 280 gross wells, down from the 300 wells in 2005. In addition, Petro-Canada obtained 396 permits for new CBM wells in 2006, with 363 applications submitted for consideration. Most of the new CBM wells are currently in the de-watering phase. U.S. Rockies operating and overhead costs were $2.29/Mcfe in 2006, compared with $1.84/Mcfe in 2005. This increase reflected costs associated with the increasing number of wells, along with general industry-wide cost pressures.

2006 Strategic Initiatives

In Western Canada, the Company commenced its planned shallow tight gas drilling program in the Medicine Hat area, and drilled more than 290 wells in 2006. The business expects to drill another 270 wells in 2007. In the southern Alberta Foothills, Petro-Canada successfully fulfilled the conditions required to earn a 60% working interest in the Sullivan natural gas field. The Company plans to seek regulatory approval in early 2007 to proceed with a multi-well development program in the Sullivan field. As part of the Company's ongoing optimization of its portfolio of assets, Petro-Canada completed the sale of its 31% working interest in the Brazeau plant and the majority of its 10% working interest in the West Pembina plant in early 2007.

In the U.S. Rockies, Petro-Canada is targeting increased CBM production with the Wild Turkey, North Shell Draw, Cedar Draw and Kingsbury projects. Increased CBM natural gas production follows a period of de-watering, which lowers the pressure in the coal seams, allowing natural gas breakthrough and production. Delays in obtaining CBM water treatment permits in 2005 pushed back the gas production increase in 2006. In February 2006, water treatment permits required for wells planned in 2005 and 2006 were approved. With water treatment permits in place, the U.S. Rockies continued to ramp up coal de-watering. Natural gas breakthrough at the Wild Turkey field occurred in the third quarter of 2006, with net production reaching 17 MMcf/d in late December. The Company continues to drill in the Denver-Julesburg Basin for natural gas from tight sands. Petro-Canada expects to double U.S. Rockies production to 100 MMcfe/d net by the end of 2007.

Furthering the strategic shift to increased unconventional production in the first half of 2006, the Company acquired approximately 50,000 net exploration acres of tight gas prone land for future development, including approximately 36,000 net acres in the Uinta Basin in eastern Utah.

During 2006, the Company continued to position itself for long-term North American supply by building its land position in Alaska and by participating in the drilling of an exploration well. At state and federal lease sales in 2006, Petro-Canada and its partners, Anadarko Petroleum Corporation and BG Group, were successful bidders on approximately 412,000 gross acres in the Alaska Foothills (a portion of this acreage remains subject to state title verification), giving each company a net land position in the Alaska Foothills of approximately one million acres, including option acreage.

Early in 2006, Petro-Canada and FEX L.P. (a subsidiary of Talisman Energy Inc.) reached a pooling agreement for the joint exploration of acreage in the National Petroleum Reserve-Alaska (NPR-A). As a result of this agreement, Petro-Canada obtained a 30% interest in the Aklaq-2 exploration well, which was drilled in the first quarter of 2006 and found to have hydrocarbons in quantities that were not commercially economical. In the latter part of 2006, FEX and Petro-Canada acquired 48 leases, or 562,000 gross acres, at the NPR-A lease sale for $10.4 million US and subsequently pooled the majority of their NPR-A leaseholdings, covering approximately 1.2 million gross acres. As a result, in jointly held NPR-A acreage with FEX, Petro-Canada's net acreage position is just over 500,000 acres.

Consistent with the Company's strategy to build long-term resources in Canada's North, Petro-Canada made an offer to acquire Canada Southern Petroleum with interests in lands in the Arctic islands. The offer was unsuccessful; however, the Company remains the largest landholder in Arctic island gas and will continue to look for opportunities to consolidate its interests in the North.

A public hearing on the proposed Gros-Cacouna LNG re-gasification terminal in Quebec was held during the second quarter of 2006. The Company expects to receive a regulatory decision in 2007.

Capital expenditures in 2006 totalled $788 million, with $532 million for exploration and development of natural gas in Western Canada, $145 million for U.S. Rockies exploration and development and $111 million for other natural gas opportunities in North America.

OUTLOOK

Production expectations in 2007

- production is expected to average about 660 MMcfe/d net of natural gas, crude oil and NGL
- unconventional gas production is expected to be about 25% of production

Action plans in 2007

- drill approximately 360 gross wells in Western Canada and approximately 300 gross wells in the U.S. Rockies
- advance long-term opportunities in Northern Canada and Alaska
- advance the re-gasification project at Gros-Cacouna to a project decision point

Capital spending plans in 2007

- approximately $400 million for replacing reserves in Western Canada core areas
- approximately $230 million directed to exploration in Western Canada, the U.S. Rockies and the Far North
- approximately $115 million for growth opportunities in the U.S. Rockies
- approximately $45 million for maintenance

The shift to longer term projects, as well as declines in Western Canada, are expected to result in approximately a 6% drop in production in 2007, compared with 2006. In 2007, about 25% of the North American Natural Gas capital spending program is expected to go to development of unconventional sources, including U.S. Rockies CBM and deep tight gas, and infill drilling in the Medicine Hat area. At the same time, the business is expected to continue with exploration.

The Company will also continue to advance long-term supply opportunities. In the Alaska NPR-A area, the Company plans to start testing our exploration lands by drilling up to three wells in 2007. As well, Petro-Canada expects to continue to advance the Gros-Cacouna LNG project. The Company, along with its partner, TransCanada PipeLines Limited, is aiming to secure regulatory approval in 2007. A joint provincial and federal government public review and consultation process took place in 2006.

Link to Petro-Canada's Corporate and Strategic Priorities

The North American Natural Gas business is aligned with Petro-Canada's strategic priorities as outlined by its progress in 2006 and goals for 2007.

	2006 RESULTS	2007 GOALS
Delivering Profitable Growth with a Focus on Operated, Long-Life Assets	▪ drilled 393 gross wells in Western Canada, including 291 wells in the Western Canada Medicine Hat region[1] ▪ drilled more than 280 gross wells, added 50,000 net acres of tight gas prone land and continued to increase CBM well de-watering in the U.S. Rockies ▪ completed regulatory hearing for the LNG facility at Gros-Cacouna ▪ increased land position in Alaska to 1.5 million net acres of leased and option lands	▪ transition further into unconventional gas plays ▪ optimize opportunities around core assets ▪ double U.S. Rockies production to 100 MMcfe/d net by year-end 2007 ▪ shift focus from developing around existing production to exploring in new areas ▪ receive regulatory decision for the LNG facility at Gros-Cacouna ▪ advance exploration prospects in the Mackenzie Delta/Corridor and Alaska
Driving for First Quartile Operation of Our Assets	▪ achieved better than 98% reliability at Western Canada facilities ▪ successfully conducted major turnaround at the Hanlan gas plant with no air licence exceedances	▪ sustain reliability performance ▪ continue to leverage costs through strategic alliances and preferred suppliers
Continuing to Work at Being A Responsible Company	▪ achieved record TRIF in Western Canada, a 40% decrease compared with 2005 ▪ improved employee and contractor safety culture through behaviour-based safety programs ▪ proactively remediated and reclaimed old sites ▪ achieved record low regulatory compliance exceedances	▪ continue to focus on TRIF and maintain low regulatory exceedances ▪ complete the roll out of behaviour-based safety for employees and contractors ▪ drive for continuous improvement in contractor safety performance ▪ proactively remediate and reclaim old sites

1 Includes wells only where Petro-Canada has a working interest.

EAST COAST OIL

BUSINESS SUMMARY AND STRATEGY

Petro-Canada is positioned in every major oil development off Canada's East Coast. The Company holds a 20% interest in Hibernia and a 27.5% interest in White Rose, and is the operator with a 34% interest in Terra Nova.

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 operating performance
- sustaining profitable production through reservoir extensions and add-ons
- pursuing high potential development projects

East Coast Oil Financial Results

(millions of Canadian dollars)		**2006**		2005		2004
Net earnings and operating earnings	**$**	**934**	**$**	**775**	**$**	**711**
Insurance premium surcharges		**(9)**		(25)		-
Income tax adjustments		**37**		(2)		3
Terra Nova insurance proceeds		**22**		2		31
Operating earnings adjusted for unusual items	**$**	**884**	**$**	**800**	**$**	**677**
Cash flow from operating activities before changes in non-cash working capital	**$**	**1,163**	$	1,062	$	993
Expenditures on property, plant and equipment and exploration	**$**	**256**	$	314	$	275
Total assets	**$**	**2,465**	$	2,442	$	2,265

2006 COMPARED WITH 2005

East Coast Oil contributed $884 million of operating earnings adjusted for unusual items, up 11% from $800 million in 2005. Strong realized prices were partially offset by lower production and increased operating expenses.

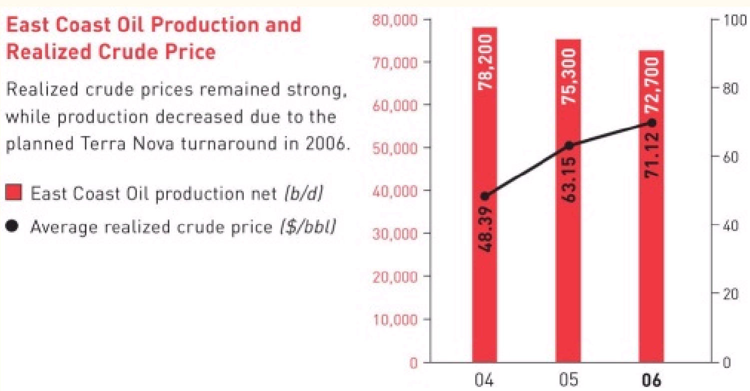
Net earnings for East Coast Oil were $934 million in 2006, up from $775 million in 2005. Net earnings in 2006 included a $37 million income tax adjustment, $22 million of insurance proceeds related to mechanical failures on the Terra Nova FPSO vessel and a $9 million insurance premium surcharge. Net earnings in 2005 included a $25 million insurance premium surcharge.

In 2006, realized crude oil prices remained strong, while production decreased due to the early shutdown and planned dry dock turnaround of the Terra Nova FPSO. East Coast Oil realized crude prices averaged $71.12/bbl in 2006, up from $63.15/bbl in 2005. Petro-Canada's share of east coast oil production averaged 72,700 b/d in 2006, down from 75,300 b/d in 2005. Lower Terra Nova production was partially offset by the addition of White Rose production.

2006 OPERATING REVIEW AND STRATEGIC INITIATIVES

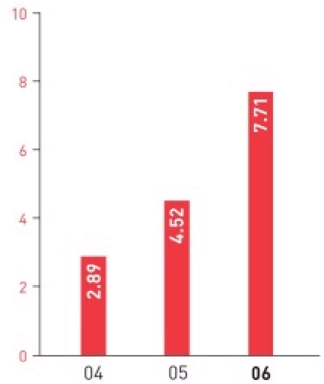
In 2006, East Coast Oil delivered record operating earnings of $934 million. White Rose ramped up production, averaging 88,000 b/d gross (24,200 b/d net), Hibernia continued to operate reliably and Terra Nova underwent its planned dry dock turnaround for regulatory inspections and reliability improvements.

2006 Operating Review



East Coast Oil Operating and Overhead Costs

Operating costs increased as a result of the Terra Nova turnaround.



East Coast operating and overhead costs *($/bbl)*

		2006		2005		2004
Production net *(b/d)*						
Hibernia		**35,700**		39,800		40,800
Terra Nova		**12,800**		33,700		37,400
White Rose		**24,200**		1,800		-
Total East Coast Oil production net		**72,700**		75,300		78,200
Average realized crude price *($/bbl)*	**$**	**71.12**	$	63.15	$	48.39
Operating and overhead costs *($/bbl)*	**$**	**7.71**	$	4.52	$	2.89

Hibernia production averaged 178,500 b/d gross (35,700 b/d net) in 2006, down from 199,000 b/d gross (39,800 b/d net) in 2005. The Hibernia platform continued to operate at first quartile levels during 2006, with lower production reflecting normal reservoir decline rates. Early in 2007, Hibernia encountered a mechanical failure on one of the platform's main power generators, thereby reducing production. While repairs are being completed, it is expected that Hibernia production will be in the range of 100,000 b/d to 110,000 b/d gross (20,000 b/d to 22,000 b/d net) for January and part of February 2007. To mitigate the impact of the main power generator repair on production, the operator advanced the planned third quarter turnaround. The planned Hibernia 30-day turnaround is expected to start in mid-February 2007.

At Terra Nova, production averaged 37,600 b/d gross (12,800 b/d net), down considerably from 99,100 b/d gross (33,700 b/d net) in 2005. Early in 2006, the first production well came on-stream in the Far East Block of the Terra Nova field. Terra Nova had a challenging year when its planned maintenance turnaround was advanced following the mechanical failure of the second of two main power generators. The completion of regulatory inspections and reliability improvements was expected to last up to 90 days, but was extended to complete necessary work. The reliability work included a 50% increase in onboard living quarters to support increased routine maintenance, repairs to gearboxes attached to two power generators and improvements to the gas compression system. In November, oil production from the Terra Nova field resumed. Petro-Canada's share of the total cost of the turnaround was approximately $77 million. In December 2006, the Terra Nova FPSO encountered a mechanical issue in a swivel on the turret system that supports water injection to the reservoir. A temporary fix was completed in late December and production returned to normal rates in excess of 100,000 b/d gross (34,000 b/d net). Full repair of the swivel is currently planned during a turnaround in the summer of 2008. The Terra Nova project reached tier one payout in the fourth quarter of 2005. As a result, royalty payments at Terra Nova increased from 5% of gross revenues to 30% of net revenues.

White Rose operated reliably in 2006, ramping up production to average 88,000 b/d gross (24,200 b/d net), compared with 6,500 b/d gross (1,800 b/d net) in 2005. The 2006 results reflected a full year of operation at White Rose.

East Coast Oil operating and overhead costs averaged $7.71/bbl in 2006, compared with $4.52/bbl in 2005. Operating costs for East Coast Oil increased as a result of the Terra Nova turnaround, excluding insurance premium surcharges and startup costs for White Rose.

2006 Strategic Initiatives

In April 2006, Petro-Canada and its partners in the Hebron development suspended negotiations with the Government of Newfoundland and Labrador and demobilized the Hebron project team after failing to reach a development agreement. Petro-Canada continues to consider Hebron a high quality asset. While project activities have been suspended at this time, Petro-Canada and its project partners remain positive that the project could proceed at a future date with the conclusion of a definitive agreement with the provincial government.

At Hibernia, a delineation well was drilled to assess the growth potential of the Southern Extension of the Hibernia reservoir in late 2005. A development plan update for the Southern Extension was filed with the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) in May 2006. The partners originally expected to receive regulatory approval of the development application in 2006, so that first production from the Southern Extension could be brought on in 2007. In January 2007, the Government of Newfoundland and Labrador rejected the decision report of the C-NLOPB to approve the development of the Hibernia Southern Extension and asked the applicants for additional information. Petro-Canada and its partners are reviewing the decision.

In 2006, the West White Rose O-28 and North Amethyst K-15 delineation wells were drilled in the west and southwest sections of the field, respectively. The White Rose O-28 well revealed a 280-metre oil column in a multi-layered reservoir and the White Rose North Amethyst K-15 well revealed a 50- to 55-metre oil column in the Ben Nevis Avalon formation with high reservoir quality. The Company and its partner are assessing the development options for both of these add-on opportunities. Also in 2006, front-end engineering and design (FEED) began on the White Rose Southern Extension. This pool, discovered in 2003, is expected to be developed as a subsea tie-back to the SeaRose FPSO. Subject to regulatory approval, production could begin in late 2009.

Capital expenditures for exploration and development of crude oil offshore Canada's East Coast were $256 million in 2006, including $106 million for the planned Terra Nova dry dock turnaround and development drilling, $88 million related to the development of the White Rose oilfield, $51 million for ongoing activities at Hibernia and $11 million for other East Coast Oil growth opportunities.

OUTLOOK

Production expectations in 2007

- production is expected to average 87,000 b/d net, reflecting a 30-day planned turnaround at Hibernia and a 16-day planned turnaround at White Rose

Growth plans

- achieve 90% operating performance at Terra Nova
- continue delineation drilling of Terra Nova's Far East Block
- conduct delineation drilling and preliminary analysis of development options for the West White Rose Block at the White Rose field
- advance Hibernia Southern Extension development plan discussions with the Government of Newfoundland and Labrador
- complete FEED on the South White Rose Extension. Project sanction will be subject to regulatory approval
- complete FEED and submit development plan to the C-NLOPB on the North Amethyst discovery at White Rose with project sanction, subject to regulatory approval, by the end of 2007

Capital spending plans in 2007

- approximately $210 million is expected to be spent on drilling to replace reserves at Hibernia, Terra Nova and White Rose, and for delineation of Terra Nova's Far East Block

East Coast Oil production is expected to be about 87,000 b/d net in 2007, compared with 72,700 b/d net in 2006. The 2007 production estimate reflects the return of Terra Nova production and higher volume forecasts at White Rose due to the addition of the sixth production well and the expected receipt of regulatory approval to produce at higher rates. These gains are expected to be partially offset by natural declines at Hibernia. A major turnaround is not planned for Terra Nova in 2007. White Rose and Hibernia have planned maintenance turnarounds of 16 and 30 days, respectively, in 2007.

Beyond 2007, the East Coast Oil business intends to offset natural declines in the main reservoirs and sustain profitable production by adding production from reservoir extensions and satellite tie-ins. The Hebron project remains a significant resource the Company would like to see developed, subject to the conclusion of a definitive agreement with the provincial government.

Link to Petro-Canada's Corporate and Strategic Priorities

The East Coast Oil business is aligned with Petro-Canada's strategic priorities as outlined by its progress in 2006 and goals for 2007.

	2006 RESULTS	2007 GOALS
Delivering Profitable Growth with a Focus on Operated, Long-Life Assets	▪ ramped up White Rose production, averaging 88,000 b/d gross (24,200 b/d net) ▪ completed drilling the West White Rose O-28 and North Amethyst K-15 delineation wells at White Rose	▪ increase reliability at Terra Nova ▪ advance in-field Hibernia growth prospects ▪ delineate West White Rose ▪ advance development plans for South White Rose Extension, North Amethyst and West White Rose prospects
Driving for First Quartile Operation of Our Assets	▪ completed Terra Nova turnaround for regulatory compliance and to improve reliability ▪ saw operating and overhead costs increase, reflecting turnaround costs at Terra Nova	▪ conduct a 30-day turnaround scheduled at Hibernia for regulatory compliance ▪ receive regulatory approval to increase annual production from SeaRose FPSO at White Rose ▪ complete 16-day turnaround at White Rose
Continuing to Work at Being A Responsible Company	▪ saw 28% decrease in TRIF, compared with 2005 ▪ accepted responsibility for an improper discharge of oil from Terra Nova in 2004, contributing $220,000 of the $290,000 fine to positive environmental projects ▪ improved the produced water system on Terra Nova, resulting in no regulatory compliance exceedances	▪ further reduce TRIF ▪ apply lessons learned from oily water discharge to prevent future incidents ▪ maintain zero regulatory exceedances

OIL SANDS

BUSINESS SUMMARY AND STRATEGY

Petro-Canada has more than 10 billion barrels of Oil Sands total resource. The Company'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 55% ownership in and operatorship of the proposed Fort Hills oil sands mining and upgrading project, and extensive oil sands acreage 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 create value
- a staged approach to development of capital-intensive Oil Sands projects to allow rigorous cost management and the opportunity to benefit from evolving technology

The Company has chosen to participate in the full oil sands value chain due to its resource potential and strong position with bitumen upgrading capacity. Petro-Canada not only has processing capacity through Syncrude and Suncor Energy Inc. (starting in 2008), but the Company is also converting the conventional crude oil train at its Edmonton refinery to refine bitumen-based feedstock from northern Alberta, starting in 2008. This conversion, along with the existing synthetic crude train, will result in the refinery running on an exclusive diet of bitumen-based feedstock. This connection between resource and upgrading capacity should provide more economic certainty in a business where volatile light/heavy differentials affect bitumen pricing.

Oil Sands Financial Results

(millions of Canadian dollars)		**2006**		2005		2004
Net earnings	**$**	**245**	**$**	**115**	**$**	**120**
Gain on sale of assets		**-**		3		-
Operating earnings	**$**	**245**	**$**	**112**	**$**	**120**
Insurance premium surcharges		**(3)**		(7)		-
Income tax adjustments		**44**		-		2
Syncrude insurance proceeds		**12**		-		-
Operating earnings adjusted for unusual items	**$**	**192**	**$**	**119**	**$**	**118**
Cash flow from operating activities before changes in non-cash working capital	**$**	**497**	$	380	$	332
Expenditures on property, plant and equipment and exploration	**$**	**377**	$	772	$	397
Total assets	**$**	**2,885**	$	2,623	$	1,883

2006 COMPARED WITH 2005

Oil Sands contributed $192 million of operating earnings adjusted for unusual items, up 61% from $119 million in 2005. Higher realized prices and production were partially offset by increased operating costs.

Net earnings for Oil Sands were $245 million in 2006, up from $115 million in 2005. Net earnings in 2006 included a $44 million income tax adjustment, $12 million of Syncrude insurance proceeds related to the 2005 hydrogen plant fire and $3 million for an insurance premium surcharge. Net earnings in 2005 included a $3 million gain on the sale of assets and a $7 million insurance premium surcharge.

Record prices and increased production at Syncrude were highlights of 2006 performance. Syncrude realized price for synthetic crude oil averaged $72.13/bbl in 2006, up from $70.41/bbl in 2005. MacKay River realized price for bitumen averaged $28.93/bbl in 2006, compared with $18.53/bbl in 2005. Oil Sands production averaged 52,200 b/d net in 2006, compared with 47,000 b/d net in 2005.

2006 OPERATING REVIEW AND STRATEGIC INITIATIVES

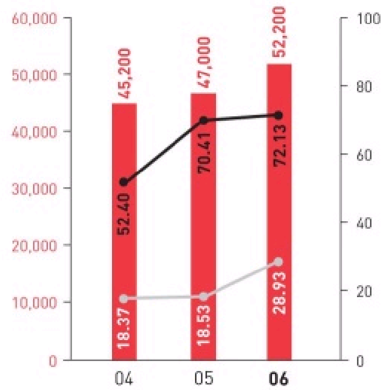
In 2006, Oil Sands delivered a record $245 million in operating earnings. Oil Sands strategic progress included selecting Sturgeon County near Edmonton as the location for the Fort Hills upgrader, filing the Sturgeon Upgrader commercial application, updating the Fort Hills mine plan, purchasing additional leases in the Fort Hills and MacKay River areas, completing the Syncrude Stage III expansion and commencing production from the third well pad at MacKay River.

2006 Operating Review

Oil Sands Production and Realized Crude and Bitumen Price

Record prices and increased overall production were the highlights of 2006 performance.

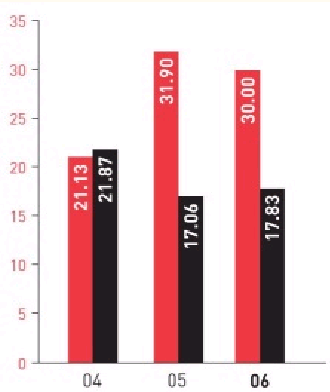
- Syncrude and MacKay River production net *(b/d)*
- Syncrude realized crude price *($/bbl)*
- MacKay River realized bitumen price *($/bbl)*



Oil Sands Operating and Overhead Costs

Syncrude unit operating and overhead costs decreased primarily due to higher production and lower natural gas costs in 2006. MacKay River unit operating and overhead costs increased due to higher costs for goods and services, partially offset by lower natural gas costs in 2006.

- Syncrude operating and overhead costs *($/bbl)*
- MacKay River operating and overhead costs *($/bbl)*



		2006		2005		2004
Production net *(b/d)*						
Syncrude		**31,000**		25,700		28,600
MacKay River		**21,200**		21,300		16,600
Total Oil Sands production net		**52,200**		47,000		45,200
Syncrude realized crude price *($/bbl)*	**$**	**72.13**	$	70.41	$	52.40
MacKay River realized bitumen price *($/bbl)*	**$**	**28.93**	$	18.53	$	18.37
Syncrude operating and overhead costs *($/bbl)*	**$**	**30.00**	$	31.90	$	21.13
MacKay River operating and overhead costs *($/bbl)*	**$**	**17.83**	$	17.06	$	21.87

Syncrude's production and unit operating costs were positively affected by the startup of the Stage III expansion in 2006. Following a brief run in May, Syncrude initiated bitumen feed into its new Coker 8-3 on August 30, 2006, enabling the Stage III expansion to come online and begin ramping up. Syncrude's production averaged 258,300 b/d gross (31,000 b/d net) in 2006, compared with 214,200 b/d gross (25,700 b/d net) in 2005. Average unit operating and overhead costs decreased to $30/bbl in 2006, down from $31.90/bbl in 2005. Lower unit operating costs were mainly due to higher production and lower natural gas costs, partially offset by Syncrude retention and incentive-based compensation. Syncrude reached royalty payout in the second quarter of 2006 and shifted to a royalty rate of 25% of net operating revenues from 1% of gross revenues. The total royalty paid in 2006 equated to a rate of 10% of gross revenues.

MacKay River's production remained flat and unit operating costs increased slightly in 2006. Production averaged 21,200 b/d in 2006, consistent with an average of 21,300 b/d in 2005, as natural declines were offset by production from the third well pad. MacKay River reliability averaged 92% in 2006, down from 98% in 2005, reflecting a gearbox failure in April. Unit operating and overhead costs increased by 5% in 2006, averaging $17.83/bbl, compared with $17.06/bbl in 2005. Higher unit operating costs were due to higher costs for goods and services, partially offset by lower natural gas costs.

2006 Strategic Initiatives

At MacKay River, work to tie-in a third well pad was completed and, in January 2006, the new well pad began steaming. Production from the new well pad commenced in the second quarter and continues to ramp up. In the third quarter of 2006, the Company purchased, for $30 million, 13 additional oil sands leases, comprising a total of 31,232 hectares immediately adjacent to Petro-Canada's existing *in situ* development at MacKay River.

In the fourth quarter of 2006, Petro-Canada announced its intention to divest its interest in the five *in situ* properties of Chard, Stony Mountain, Liege, Thornbury and Ipiatik. The sale process attracted considerable attention; however, the bids received did not meet Petro-Canada's expectation; therefore, the Company will not divest its interests at this time.

Syncrude completed construction of the Stage III expansion project at a total cost of $8.2 billion ($1 billion net). At full capacity, the Stage III expansion is expected to add approximately 100,000 b/d gross (12,000 b/d net) and increase the quality of all of Syncrude's sweet synthetic production.

In early 2006, the Fort Hills partners acquired two additional leases adjacent to the existing Fort Hills leases to afford greater mine planning flexibility. The initial phase of mine production is expected to be in the range of 100,000 b/d to 170,000 b/d gross (55,000 b/d to 93,500 b/d net) of bitumen. The partners selected Sturgeon County, 40 kilometres northeast of Edmonton, as the location for the upgrading facility to process bitumen from the Fort Hills mine. The upgrader is expected to produce in the range of 85,000 b/d to 145,000 b/d gross (46,750 b/d to 79,750 b/d net) of synthetic crude oil, with first bitumen production in the 2011 time frame. The Company expects to complete the design basis memorandum (DBM) and preliminary cost estimates for the project by mid-2007.

Oil Sands capital expenditures of $377 million in 2006 included $151 million for the Fort Hills development, $102 million for the Syncrude Stage III expansion and operations, $86 million for MacKay River and $38 million for the acquisition of 13 additional leases adjacent to MacKay River, and other *in situ* projects.

OUTLOOK

Production expectations in 2007

- Petro-Canada's share of Syncrude production is expected to average 34,000 b/d net
- MacKay River bitumen production is expected to average 24,000 b/d net

Growth plans

- work to improve reliability at Syncrude
- increase water handling capacity and bitumen production at MacKay River
- advance the Fort Hills oil sands mining and upgrading project
- progress SAGD technology through research and development

Capital spending plans in 2007

- approximately $550 million to advance the Fort Hills development and the MacKay River expansion
- approximately $130 million to enhance existing operations at Syncrude and MacKay River
- approximately $60 million to replace reserves through ongoing pad development at MacKay River
- approximately $30 million to advance development of *in situ* oil sands leases

Oil Sands production is expected to increase to 58,000 b/d net in 2007, compared with 52,200 b/d net in 2006. Higher expected production in 2007 is due to a full year of production from the Syncrude Stage III expansion and increased production at MacKay River. The total Syncrude royalty payable in 2007 is expected to equate to a rate of between 10% and 15% of gross revenue, depending on crude oil prices. The total MacKay River royalty payable in 2007 is expected to be 1% of gross revenue.

In 2007, the Company expects to complete the Fort Hills mine, extraction and upgrading DBM, which establishes key design parameters and a more detailed project schedule. Petro-Canada expects to receive a regulatory decision on the filed commercial application for the Sturgeon Upgrader by mid-2008.

The Oil Sands business has a capital program of about $770 million in 2007. Capital for new growth opportunities of $550 million includes funding the preliminary engineering and design for the Fort Hills project (forecast to be $315 million) and the FEED for the MacKay River expansion (forecast to be $235 million). Spending to enhance existing operations and comply with regulations at Syncrude is budgeted to be $75 million in 2007. Capital for enhancing existing operations and improving base business profitability at MacKay River is expected to be approximately $55 million in 2007.

With the initial phase of Fort Hills and the MacKay River expansion, Petro-Canada's production will grow to more than 150,000 b/d net. Beyond that, the Company has the potential to grow the Oil Sands business to approximately 350,000 b/d net over the next decade. Challenges to implementation of the strategy include capital cost pressures, skilled labour shortages, and environmental and stakeholder issues. As an experienced and responsible operator, Petro-Canada is well positioned to meet these challenges.

Link to Petro-Canada's Corporate and Strategic Priorities

The Oil Sands business is aligned with Petro-Canada's strategic priorities as outlined by its progress in 2006 and goals for 2007.

	2006 RESULTS	2007 GOALS
Delivering Profitable Growth with a Focus on Operated, Long-Life Assets	▪ selected Sturgeon County for Fort Hills upgrader location ▪ submitted commercial application for Sturgeon Upgrader ▪ acquired additional oil sands leases adjacent to MacKay River and the existing Fort Hills leases ▪ Syncrude Stage III expansion came on-stream	▪ complete Fort Hills DBM and initial cost estimate, and initiate FEED ▪ receive regulatory decision on MacKay River expansion project ▪ continue ramp up of Syncrude Stage III expansion ▪ complete MacKay River water handling capacity upgrade and tie-in a fourth well pad so that production can increase in 2008
Driving for First Quartile Operation of Our Assets	▪ saw Syncrude non-fuel unit operating costs decrease by 5%, compared with 2005 ▪ saw MacKay River unit operating costs increase by 5%, compared with 2005, reflecting Alberta business environment ▪ saw Syncrude enter into a Management Services agreement with Imperial Oil Resources for operational, technical and business services ▪ maintained reliability at MacKay River at 92%	▪ decrease MacKay River non-fuel unit operating costs by 10%, compared with 2006 ▪ decrease Syncrude non-fuel unit operating costs by 10%, compared with 2006 ▪ sustain MacKay River reliability at greater than 90%
Continuing to Work at Being A Responsible Company	▪ TRIF decreased by 46%, compared with 2005	▪ maintain focus on TLM and Zero-Harm ▪ ensure regulators, First Nations and other key stakeholders affected by major projects are properly consulted and engaged

INTERNATIONAL

BUSINESS SUMMARY AND STRATEGY

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, with exploration activities extending into Denmark and Norway. The North Africa/Near East region provides crude oil production from assets in Libya, with exploration activity extending into Syria, Algeria, Tunisia and Morocco. In addition, a natural gas development is underway in Syria. In Northern Latin America, operations are focused in Trinidad and Tobago, and Venezuela.

The International strategy is to access a sizable resource base using a three-fold approach to:

- optimize and leverage existing assets
- seek out new, long-life opportunities
- execute a substantial and balanced exploration program

In 2005, Petro-Canada reached an agreement to sell the Company's mature producing assets in Syria. The sale was closed on January 31, 2006. These assets and associated results are reported as discontinued operations and excluded from continuing operations.

International Financial Results

(millions of Canadian dollars)		**2006**		2005		2004
Net earnings (loss) from continuing operations	**$**	**(206)**	**$**	**(109)**	**$**	**116**
Unrealized loss on Buzzard derivative contracts		**(240)**		(562)		(205)
Gain on sale of assets		**12**		-		8
Operating earnings from continuing operations	**$**	**22**	**$**	**453**	**$**	**313**
Insurance premium surcharges		**(8)**		(18)		-
Scott insurance proceeds		**3**		-		-
Income tax adjustments[1]		**(242)**		29		-
Operating earnings from continuing operations adjusted for unusual items	**$**	**269**	**$**	**442**	**$**	**313**
Cash flow from continuing operating activities before changes in non-cash working capital	**$**	**716**	$	770	$	768
Expenditures on property, plant and equipment and exploration from continuing operations	**$**	**760**	$	696	$	1,707
Total assets from continuing operations	**$**	**6,031**	$	4,856	$	4,969

1 In 2006, the Company recorded a $242 million charge for the U.K. supplemental corporate tax rate adjustment.

2006 COMPARED WITH 2005

International contributed $269 million of operating earnings from continuing operations adjusted for unusual items, down 39% from $442 million in 2005. Lower production, tax adjustments in Northwest Europe, higher exploration, depreciation, depletion and amortization costs, and foreign exchange losses were partially offset by higher realized prices. In 2006, cash flow from continuing operating activities before changes in non-cash working capital remained strong at $716 million, compared with $770 million in 2005.

International net loss from continuing operations was $206 million in 2006, compared with a net loss of $109 million in 2005. Net loss from continuing operations in 2006 included an unrealized loss on the Buzzard derivative contracts of $240 million, a $242 million charge for the U.K. supplemental corporate tax rate adjustment, a $12 million gain on the sale of non-core assets, an $8 million insurance premium surcharge and $3 million in insurance proceeds from the Scott platform fire. Net loss from continuing operations in 2005 included an unrealized loss on the Buzzard derivative contracts of $562 million, an $18 million insurance premium surcharge and a $29 million positive adjustment for income tax rate and other tax adjustments.

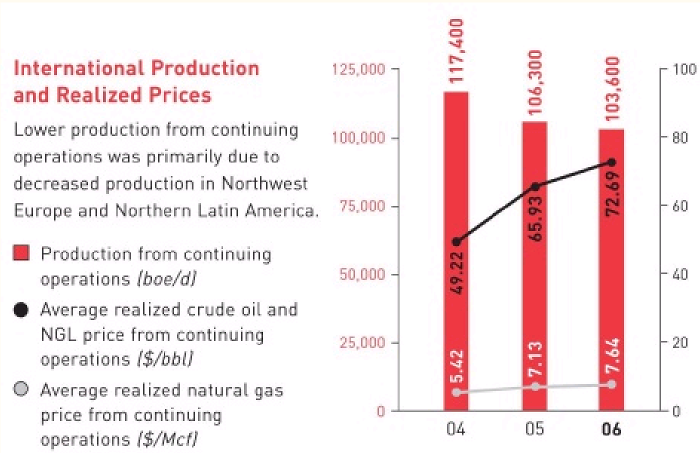
International production from continuing operations averaged 103,600 barrels of oil equivalent/day (boe/d) net in 2006, compared with 106,300 boe/d net in 2005. The decrease was primarily due to lower production in Northwest Europe and Northern Latin America. International crude oil and liquids realized prices from continuing operations averaged $72.69/bbl and natural gas realized prices averaged $7.64/Mcf in 2006, compared with $65.93/bbl and $7.13/Mcf, respectively, in 2005. Operating and overhead costs from continuing operations averaged $7.61/boe in 2006, flat compared with $7.60/boe in 2005.

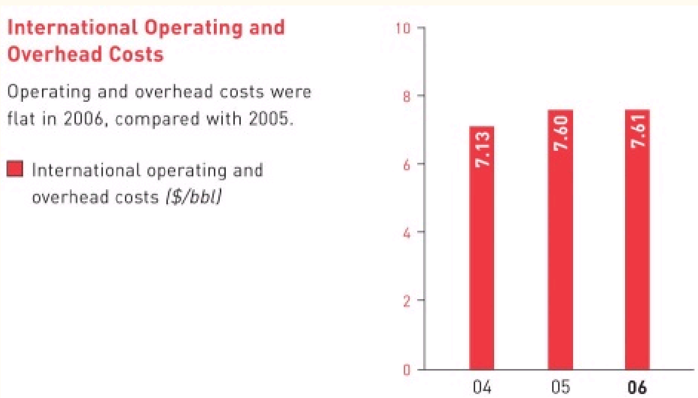
International capital expenditures from continuing operations in 2006 were $760 million, with $588 million directed to Northwest Europe, primarily for North Sea developments, $120 million invested in the North Africa/Near East region and $52 million going toward the Northern Latin America region and other capital projects.

2006 OPERATING REVIEW AND STRATEGIC INITIATIVES

The International business strengthened its production profile by delivering first production from De Ruyter and L5b-C. The business also enhanced its portfolio of assets with the acquisition of long-life natural gas assets in Syria in 2006.

2006 Operating Review





		2006		2005		2004
Production from continuing operations net *(boe/d)*						
Northwest Europe		**43,700**		44,600		54,600
North Africa/Near East		**49,400**		49,800		50,900
Northern Latin America		**10,500**		11,900		11,900
Total International production net		**103,600**		106,300		117,400
Average realized crude oil and NGL price from continuing operations *($/bbl)*	**$**	**72.69**	$	65.93	$	49.22
Average realized natural gas price from continuing operations *($/Mcf)*	**$**	**7.64**	$	7.13	$	5.42
Operating and overhead costs from continuing operations *($/boe)*	**$**	**7.61**	$	7.60	$	7.13

Northwest Europe

Petro-Canada's Northwest Europe production averaged 43,700 boe/d net in 2006, compared with 44,600 boe/d net in 2005. Natural declines in the U.K. and the Netherlands sectors of the North Sea were partially offset by new production from De Ruyter and L5b-C. Northwest Europe crude oil and liquids realized prices averaged $72.67/bbl and natural gas averaged $8.91/Mcf in 2006, compared with $66.13/bbl and $7.35/Mcf, respectively, in 2005.

During 2006, Petro-Canada continued to leverage its existing infrastructure through concentric development near core areas and through new discoveries. Although the basin is mature, the Company continues to secure new developments, including the Buzzard, Pict and Saxon fields in the U.K. sector of the North Sea, and the De Ruyter and L5b-C fields in the Netherlands sector of the North Sea.

In the U.K. sector of the North Sea, the Buzzard development, in which the Company has a 29.9% interest, achieved first oil in January 2007. The field is expected to ramp up to peak production in mid-2007. In 2006, a rig was secured to complete a 12-month program of development, in fill and exploration drilling, which began in early 2007. This program includes completing the Saxon project, a Pict look-alike 100% owned and operated by Petro-Canada. The Saxon development will be tied back to the Triton area infrastructure and is expected to be on-stream at the end of 2007, with peak production of approximately 7,000 boe/d gross. Following the discovery in 2005 on the Petro-Canada operated 13/27a Block (90% working interest), the Company farmed into adjacent Blocks 13/26a and 13/26b in September 2006, obtaining a 27.5% non-operated working interest. Appraisal drilling to test the extent of the 13/27a discovery is planned by the operator for the second half of

2007. In late 2006, the Golden Eagle discovery was made on the non-operated Block 20/1 North located near the Buzzard field. The Company has a 25% working interest in this licence and work is ongoing to assess the possible development of the discovery. In early 2007, Petro-Canada was awarded Block 13/24d near Buzzard in the U.K. 24^{th} licensing round. The Company is operator with a 90% working interest.

In the Netherlands sector of the North Sea, the De Ruyter and L5b-C developments achieved first production in 2006. De Ruyter, a Petro-Canada operated oil development, came on-stream in late September and delivered 5,500 boe/d gross (2,970 boe/d net) in 2006. The Company has a 54.07% working interest in De Ruyter, which is expected to add around 10,000 boe/d net to Petro-Canada in 2007. L5b-C, a non-operated asset in which the Company holds a 30% working interest, achieved first gas in mid-November 2006 and is expected to add 3,000 boe/d net to Petro-Canada in 2007. Two offshore exploration wells near the De Ruyter field are planned during 2007 and the Company expects to participate in one other non-operated exploration well in 2007.

In 2006, Petro-Canada opened an office in Stavanger, Norway, following the award of five production licences in the Norwegian sector of the North Sea in the 2005 Awards in Predefined Areas (APA). In 2007, the Company was awarded seven additional production licences in the 2006 APA round. Petro-Canada is operator of four of the 12 licences in Norway.

Technical and commercial studies relating to development scenarios were undertaken on the Hejre field in Denmark in 2006. A non-operated licence (20% working interest) was acquired adjacent to the Hejre field as protection acreage for the discovery in 2006. The Stork and Robin prospects were drilled and completed as dry holes. This resulted in the Company's decision to relinquish the Robin licence in January 2007. The exploration period on the Svane discovery was extended by two years in 2006 to complete technical and economic re-evaluation.

North Africa/Near East

In 2006, Petro-Canada's production from continuing operations in this region averaged 49,400 boe/d net, relatively unchanged from 49,800 boe/d net in 2005. North Africa/Near East crude oil and liquids realized prices from continuing operations averaged $72.70/bbl in 2006, compared with $65.79/bbl in 2005.

In the North Africa/Near East region, Petro-Canada continues to assess the significant future resource potential, using the Company's experience and assets in the area as leverage for long-term growth.

In Syria, the Company completed the sale of its mature producing assets in early 2006. In November, Petro-Canada acquired operatorship and a 90% interest in a Production-Sharing Contract (PSC) in the Ash Shaer and Cherrife natural gas fields for $54 million. Under the agreement, Petro-Canada expects to develop and produce an estimated 80 MMcf/d of natural gas, with first gas anticipated in 2010. In addition, preparations for drilling on Block II progressed, with two exploration wells expected to be drilled in 2007.

In 2006, nine development wells were drilled in the producing fields in Libya, of which seven were completed. A further three exploration wells were drilled, with one new discovery on existing concessions. In 2007, Petro-Canada expects to participate in three exploration and appraisal wells with Veba Oil Operations. The Company was awarded an exploration licence in the Libyan third round exploration and production-sharing agreement (EPSA) IV auction. The onshore licence is located in the Sirte Basin and Petro-Canada is the operator with a 50% working interest.

Petro-Canada spudded an exploration well on the Zotti Block in Algeria in late 2006. In Tunisia, the Company closed its Tunis office and relinquished its 72.5% interest in the Melitta Block after completing its work commitment. The Company intends to focus on exploration on the offshore, non-operated Cap Serrat and Bechateaur permits in 2007 (33% working interest). In Morocco, Petro-Canada extended its reconnaissance licence by another 12 months on the Bas Draa Block. A gravity magnetic survey will take place on the block in the first half of 2007.

Northern Latin America

In 2006, Petro-Canada's share of Trinidad and Tobago production averaged 63 MMcf/d net, down from 72 MMcf/d net in 2005. This was due to a reduction in overall processing capacity at the Atlantic LNG plant, following maintenance on Trains 2 and 3 and delays in commissioning Train 4. Northern Latin America realized prices for natural gas averaged $5.13/Mcf in 2006, compared with $6.62/Mcf in 2005.

In Trinidad and Tobago, 3D seismic surveys on offshore Blocks 1a, 1b and 22, covering a total area of 4,433 square kilometres, were completed in 2006. Long lead materials were secured and drilling rigs contracted to complete a drilling program of up to eight exploration wells starting in 2007. The evaluation of seismic data and work to obtain environmental approvals for the drilling program progressed in 2006. The Company continues to develop its 17.3% working interest in the North Coast Marine Area (NCMA-1) asset. Phase 3a and 3b subsea tie-backs to the Hibiscus platform were completed and first natural gas was achieved in late 2006. Phase 3c was approved and will involve the development of the Poinsettia field with a platform and pipeline tie-back to the Hibiscus platform. Production is expected to come on-stream by early 2009.

In Venezuela, the La Ceiba field development plan is awaiting approval by the Venezuelan authorities. Petro-Canada has a 50% non-operated interest in the field.

OUTLOOK

Production expectations in 2007

- North Africa/Near East oil and gas production to average 49,000 boe/d net
- Northwest Europe oil and gas production to average 85,000 boe/d net
- Northern Latin America natural gas production to average 66 MMcf/d net

Growth plans

- advance Saxon development for 2007 startup
- execute the exploration program in Northern Latin America, Northwest Europe and North Africa/Near East
- advance natural gas development in Syria
- continue to pursue new business opportunities in LNG

Capital spending plans in 2007

- approximately $340 million for reserves replacement spending in core areas
- approximately $275 million primarily for new growth projects in Syria and the North Sea
- approximately $250 million for exploration and new ventures

International production from continuing operations is expected to be about 145,000 boe/d net in 2007, compared with 103,600 boe/d net in 2006. The anticipated 40% increase in production in 2007 reflects contributions from new development projects, such as De Ruyter, Buzzard, L5b-C and Saxon. These projects are expected to more than offset the 15% to 20% natural declines in Northwest Europe.

The Company continues to advance discussions on importing gas from Russia to North America through a joint LNG project with OAO «Gazprom» (Gazprom). The liquefaction plant proposed in the St. Petersburg region is expected to export 3.5 million tonnes to 5 million tonnes per annum (or 500 MMcf/d to 700 MMcf/d) of gas supplied from the Russian grid. An agreement was signed with Gazprom in March 2006 to proceed with the initial engineering design of the liquefaction plant. The preliminary engineering studies will provide cost and schedule estimates from which the Company may proceed into detailed design and engineering for the liquefaction plant.

Link to Petro-Canada's Corporate and Strategic Priorities

The International business is aligned with Petro-Canada's strategic priorities as outlined by its progress in 2006 and goals for 2007.

	2006 RESULTS	2007 GOALS
Delivering Profitable Growth with a Focus on Operated, Long-Life Assets	▪ achieved first production at De Ruyter and L5b-C ▪ closed sale of mature Syrian producing assets ▪ acquired 90% interest and became operator of the Ash Shaer and Cherrife gas project ▪ secured drilling rigs for 2007 and 2008 exploration programs ▪ awarded Sirte licence in Libyan third round EPSA IV auction	▪ ramp up Buzzard and L5b-C to full production ▪ achieve first production at Saxon in the U.K. sector of the North Sea by year end ▪ participate in up to a 17-well exploration drilling program, (depending on rig arrival dates) with balanced risk profile over the next 18 months ▪ commence field appraisal and project design activities on Ash Shaer and Cherrife development ▪ establish a Libyan exploration program on the newly acquired Sirte exploration block ▪ actively pursue LNG supply opportunities
Driving for First Quartile Operation of Our Assets	▪ achieved more than 95% uptime on Hanze platform ▪ achieved full production capacity at De Ruyter platform ahead of schedule ▪ seconded specialists to support Libyan operations ▪ improved Scott platform reliability and uptime by 33%, compared with 2005	▪ maintain excellent reliability at De Ruyter platform ▪ optimize production capacity on Triton area assets by implementing recommendations from de-bottlenecking study
Continuing to Work at Being A Responsible Company	▪ had nine recordable injuries in 2006, compared with 14 in 2005, but TRIF rose to 0.8 in 2006, compared with 0.62 in 2005, reflecting fewer person hours worked ▪ achieved five years of continuous operations on the Hanze platform without a lost-time incident ▪ provided safety training and equipment to fishermen in Trinidad and Tobago as part of community liaison activities during seismic operations	▪ maintain focus on TRIF and increase leadership visibility of Zero-Harm effort ▪ reduce oil in produced water at Triton ▪ collaborate with local stakeholders in Trinidad and Tobago to minimize impact of offshore drilling

Discontinued Operations

On January 31, 2006, Petro-Canada completed the sale of the Company's producing assets in Syria to a joint venture of companies owned by India's Oil and Natural Gas Corporation Limited and the China National Petroleum Corporation for net proceeds of $640 million. The sale resulted in a gain on disposal of $134 million recorded in the first quarter of 2006. This sale aligned with Petro-Canada's strategy to increase the proportion of long-life and operated assets within its portfolio. Petro-Canada's activities in Syria remain part of the North Africa/Near East producing region, with an active exploration program in Block II and the addition of the Ash Shaer and Cherrife natural gas projects in Syria during 2006.

Producing assets in Syria are presented as discontinued operations in the Consolidated Financial Statements. Petro-Canada's net earnings from discontinued operations in 2006 were $152 million and included a gain on disposal of $134 million. Summary information is presented on the following page. Additional information concerning Petro-Canada's discontinued operations can be found in Note 4 to the Consolidated Financial Statements.

Discontinued Financial Results

(millions of Canadian dollars, unless otherwise noted)		**2006**		2005		2004
Net earnings from discontinued operations	**$**	**152**	**$**	**98**	**$**	**59**
Gain on sale of assets		**134**		-		-
Operating earnings from discontinued operations	**$**	**18**	**$**	**98**	**$**	**59**
Insurance premium surcharges		**-**		(2)		-
Operating earnings from discontinued operations adjusted for unusual items	**$**	**18**	**$**	**100**	**$**	**59**
Cash flow from operating activities before changes in non-cash working capital	**$**	**17**	$	245	$	204
Expenditures on property, plant and equipment and exploration	**$**	**1**	$	46	$	62
Total assets	**$**	**-**	$	648	$	985
Total volumes *(boe/d)*						
- net before royalties		**5,500**		70,100		79,200
- net after royalties		**1,400**		21,000		24,200
Average realized crude oil and NGL price *($/bbl)*	**$**	**71.84**	$	61.82	$	46.70
Average realized natural gas price *($/Mcf)*	**$**	**7.94**	$	6.43	$	4.81

UPSTREAM PRODUCTION

2006 COMPARED WITH 2005

In 2006, Petro-Canada's production from continuing operations of crude oil, NGL and natural gas averaged 345,400 boe/d net, down from 354,600 boe/d net in 2005.

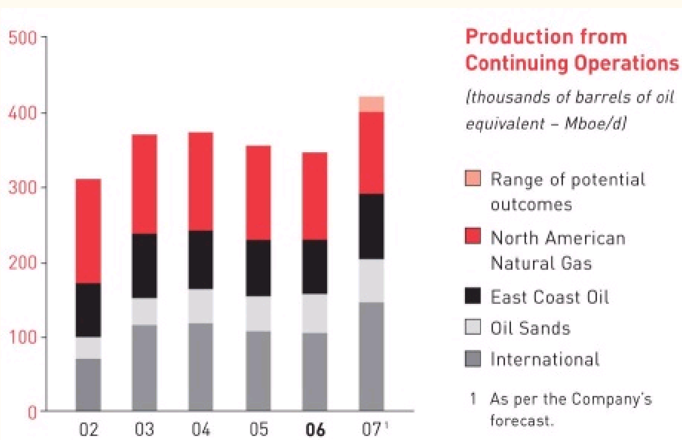
2006 Average Daily Production Volumes Net	**North American Natural Gas**	**East Coast Oil**	**Oil Sands**	**International**	**Total**
Crude oil, NGL and bitumen *(b/d)*					
- net before royalties	**14,200**	**72,700**	**21,200**	**82,600**	**190,700**
- net after royalties	**10,800**	**68,500**	**20,800**	**77,900**	**178,000**
Synthetic crude oil *(b/d)*					
- net before royalties	**-**	**-**	**31,000**	**-**	**31,000**
- net after royalties	**-**	**-**	**28,000**	**-**	**28,000**
Natural gas *(MMcf/d)*					
- net before royalties	**616**	**-**	**-**	**126**	**742**
- net after royalties	**489**	**-**	**-**	**95**	**584**
Continuing operations *(boe/d)*					
- net before royalties	**116,900**	**72,700**	**52,200**	**103,600**	**345,400**
- net after royalties	**92,300**	**68,500**	**48,800**	**93,700**	**303,300**
Discontinued operations *(boe/d)*					
- net before royalties	**-**	**-**	**-**	**5,500**	**5,500**
- net after royalties	**-**	**-**	**-**	**1,400**	**1,400**
Total volumes *(boe/d)*					
- net before royalties	**116,900**	**72,700**	**52,200**	**109,100**	**350,900**
- net after royalties	**92,300**	**68,500**	**48,800**	**95,100**	**304,700**

2005 Average Daily Production Volumes Net	North American Natural Gas	East Coast Oil	Oil Sands	International	Total
Crude oil, NGL and bitumen *(b/d)*					
- net before royalties	14,700	75,300	21,300	83,500	194,800
- net after royalties	11,200	69,600	21,100	77,700	179,600
Synthetic crude oil *(b/d)*					
- net before royalties	-	-	25,700	-	25,700
- net after royalties	-	-	25,400	-	25,400
Natural gas *(MMcf/d)*					
- net before royalties	668	-	-	138	806
- net after royalties	512	-	-	95	607
Continuing operations *(boe/d)*					
- net before royalties	126,000	75,300	47,000	106,300	354,600
- net after royalties	96,500	69,600	46,500	93,500	306,100
Discontinued operations *(boe/d)*					
- net before royalties	-	-	-	70,100	70,100
- net after royalties	-	-	-	21,000	21,000
Total volumes *(boe/d)*					
- net before royalties	126,000	75,300	47,000	176,400	424,700
- net after royalties	96,500	69,600	46,500	114,500	327,100

2007 Production Outlook

Upstream production is expected to increase in 2007 with additional volumes from Buzzard, Terra Nova, the Syncrude expansion, De Ruyter and L5b-C. Offsetting these increases are lower production from North American Natural Gas and natural declines in the North Sea. Production is expected to average in the range of 390,000 boe/d net to 420,000 boe/d net in 2007, up from 2006.

Factors that may impact production during 2007 include reservoir performance, drilling results, facility reliability (particularly at Terra Nova), ramp up of production at Buzzard, De Ruyter and L5b-C, regulatory approval of increased facility throughput at White Rose and the successful execution of planned turnarounds.



Consolidated Production from Continuing Operations Net

(thousands of boe/d)	**2007 Outlook** *(+/-)*
North American Natural Gas	
Natural gas	**97**
Liquids	**13**
East Coast Oil	**87**
Oil Sands	
Syncrude	**34**
MacKay River	**24**
International	
North Africa/Near East [1]	**49**
Northwest Europe	**85**
Northern Latin America	**11**
Total continuing operations	**390 - 420**

1 North Africa/Near East excludes production from the mature Syrian producing assets sold in 2006.

Reserves Summary

The Company's reserves data and reserves quantities are determined by Petro-Canada's staff of qualified reserves evaluators using corporate-wide policies, procedures and practices. These reserves policies, procedures and practices conform with the requirements in Canada, as well as with the U.S. SEC and the Association of Professional Engineers, Geologists and Geophysicists of Alberta's Standard of Practice for the Evaluation of Oil and Gas Reserves for Public Disclosure. Petro-Canada also employs independent third parties to evaluate, audit and/or review its reserves processes and estimates. In 2006, 53% of North American (or 34% if Syncrude oil sands mining is included) and 29% of International proved oil and gas reserves were assessed by independent reserves evaluators. The independent reserves evaluators concluded that the Company's year-end reserves estimates were reasonable.

December 31, 2006 Consolidated Reserves[1]	**Proved Liquids**	**Proved Gas**	**Proved Reserves Additions Liquids**[3]	**Proved Reserves Additions Gas**[3]	**Proved**[2]	**Proved Reserves Additions**[3]
(working interest before royalties)	*(MMbbls)*	*(Billion cubic feet - Bcf)*	*(MMbbls)*	*(Bcf)*	*(Million bbls of oil equivalent - MMboe)*	*(MMboe)*
North American Natural Gas	47	1,645	3	44	321	10
East Coast Oil	123	-	18	-	123	18
Oil Sands [4]	502	-	179	-	502	179
International [5]	278	300	(35)	(24)	328	(39)
Total	950	1,945	165	20	1,274	168
Production net	81	270				126
Proved replacement ratio [6, 7]						134%

1 A comparative table for 2006 versus 2005 is shown on page 78.
2 At year-end 2006, 63% of proved reserves were classified as proved developed reserves. Of the total undeveloped reserves, 95% are associated with large projects currently producing or under active development, including Buzzard, Syncrude, MacKay River, Hibernia, Terra Nova, White Rose, and Trinidad and Tobago natural gas.
3 Proved reserves additions are the sum of revisions of previous estimates, net purchases/sales, and discoveries, extensions and improved recovery in 2006. Further detail on these categories is provided in the reserves table on page 78.
4 Oil Sands proved reserves include reserves from Syncrude and MacKay River. Syncrude is an oil sands mining operation. Oil sands mining is not an oil and gas activity as defined by the SEC. The mining proved reserves are estimated in accordance with the SEC Industry Guide 7.
5 The year-end reserves reflect Petro-Canada's sale of its mature Syrian producing assets on January 31, 2006. The 2005 year-end Syrian proved reserves were 49 MMboe. The 2006 production presented does not include any production from the Syrian producing assets.
6 This ratio is the year-over-year net change in proved reserves (before deducting production), divided by annual production over the same time period. Proved reserves replacement ratio is a general indicator of the Company's reserves growth. It is only one of a number of metrics that can be used to analyse a company's upstream business.
7 Reserves replacement ratio and reserves life index are non-standardized measures and may not be comparable to similar measures of other companies. They are illustrative only.

December 31, 2006	
Five-year proved plus probable replacement ratio	**175%**
Proved plus probable reserves life index [8,9]	**17.3**

8 This index is proved plus probable reserves at year-end 2006, divided by annual production.

Petro-Canada's objective is to replace reserves over time through exploration, development and acquisition. The Company believes that, due to the specific nature of its upstream portfolio and attributes of its probable reserves, the combination of proved plus probable reserves provides the best perspective of Petro-Canada's reserves. Petro-Canada's proved plus probable reserves replacement on a consolidated basis was 175%[9] over the last five years. The proved plus probable reserves life index was 17.3[9] years at year-end 2006, compared with 14.7 years at year-end 2005.

In 2006, the Company replaced 134%[9] of production on a proved basis. Proved reserves additions totalled 168 MMboe[9], compared with 2006 production of 126 MMboe net[9]. As a result, total proved reserves increased from 1,232 MMboe[9] at year-end 2005 to 1,274 MMboe[9] at year-end 2006.

The North American Natural Gas business added 10 MMboe of proved reserves additions in 2006. Lower than expected reserves additions reflected technical revisions related to reservoir performance of some Western Canada pools and application of year-end natural gas prices as stipulated by the SEC. These factors were partially offset by reserves additions from exploration and development activity.

9 Reserves replacement ratio and reserves life index are non-standardized measures and many not be comparable to similar measures of other companies. They are illustrative only. Company total proved reserves include oil and gas activity proved reserves plus oil sands mining proved reserves (oil sands mining reserves - 345 MMbbls and 2006 annual production - 11 MMbbls).

In East Coast Oil, 18 MMbbls were added to proved reserves during 2006. This was due to ongoing development well drilling at White Rose, Terra Nova and Hibernia.

In 2006, 179 MMbbls of proved reserves were added in Oil Sands[1]. At MacKay River, year-end bitumen prices resulted in positive economics, permitting the booking of proved reserves in compliance with SEC guidance. Development and delineation drilling, combined with an increased proved recovery factor, resulted in the addition of 165 MMbbls of proved reserves at MacKay River. At Syncrude, 14 MMbbls were added to proved reserves, reflecting extraction efficiencies.

International proved reserves declined by 39 MMboe in 2006 due to the sale of the mature Syrian producing assets. Partially offsetting this decline was the addition of proved reserves at Buzzard.

Further detail on Petro-Canada's reserves is provided in the reserves table at the end of this report (see page 78).

Downstream

Montreal refinery

Lubricants plant in Mississauga

One of more than 1,300 retail stations in Canada

One of 219 PETRO-PASS locatic in Canada

BUSINESS SUMMARY AND STRATEGY

Petro-Canada is the second largest Downstream business and the "brand of choice" in Canada. In 2006, Petro-Canada accounted for approximately 13% of the total refining capacity in Canada and about 16% of total petroleum products sold in Canada.

Downstream operations include two refineries - one in Edmonton and one in Montreal - with a total daily rated capacity of 40,500 cubic metres/day (m^3/d) (255,000 b/d), a lubricants plant - the largest producer of lubricant base stocks in Canada, a network of more than 1,300 retail service stations, Canada's largest commercial road transport network of 219 locations and a robust bulk fuel sales channel.

The strategy in the Downstream business is to increase the profitability of the base business through effective capital investment and disciplined management of controllable factors. In 2007, planned Downstream capital investment will shift to growth projects as regulatory projects to produce cleaner burning fuels were completed in 2006. The Downstream business' goal is to deliver superior returns and growth, including a 12% return on capital employed (ROCE) based on a mid-cycle business environment. Key features of the strategy include:

- achieving and maintaining first quartile operating performance in all areas
- advancing Petro-Canada as the "brand of choice" for Canadian gasoline consumers
- increasing sales of high margin specialty lubricants

The trend toward increased heavy crude production globally has resulted in increased need for refining capacity that can process this feedstock. As a result, Petro-Canada is converting the conventional crude oil train at its Edmonton refinery to refine bitumen-based feedstock from northern Alberta, with completion expected by 2008. The Edmonton refinery conversion project is expected to add earnings and cash flow starting in 2008. As well, the Company is considering construction of a 25,000 b/d coker at its Montreal refinery. An investment decision on a new coker at the Montreal refinery is expected to be made in 2007. If the coker project is approved, completion is targeted for late 2009 and is expected to add earnings and cash flow in 2010.

1 Oil Sands proved reserves include reserves from Syncrude and MacKay River. Syncrude is an oil sands mining operation. Oil sands mining is not an oil and gas activity as defined by the SEC. The mining proved reserves are estimated in accordance with the SEC Industry Guide 7.

Downstream Financial Results

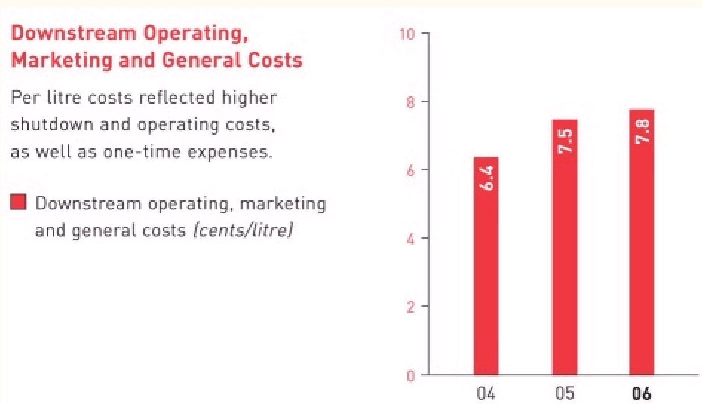
(millions of Canadian dollars)		**2006**		2005		2004
Net earnings	**$**	**473**	**$**	**415**	**$**	**314**
Gain on sale of assets		**10**		17		4
Operating earnings	**$**	**463**	**$**	**398**	**$**	**310**
Insurance premium surcharges		**(8)**		(23)		-
Income tax adjustments		**41**		(2)		2
Oakville closure costs		**-**		2		(46)
Operating earnings adjusted for unusual items	**$**	**430**	**$**	**421**	**$**	**354**
Cash flow from operating activities before changes in non-cash working capital	**$**	**790**	$	607	$	556
Expenditures on property, plant and equipment	**$**	**1,229**	$	1,053	$	839
Total assets	**$**	**6,649**	$	5,609	$	4,462

2006 COMPARED WITH 2005

Downstream contributed $430 million of operating earnings adjusted for unusual items, up 2% from $421 million in 2005. Strong reliability at the Edmonton and Montreal refineries allowed Petro-Canada to maximize the benefits of favourable refining margins and a wider light/heavy crude price differential. These benefits were partially offset by the impact of higher operating costs associated with the planned refinery turnarounds in the second quarter, higher energy prices and one-time expenses incurred due to a fire at the Mississauga lubricants plant.

Net earnings from Downstream were a record $473 million in 2006, up from $415 million in 2005. Net earnings in 2006 included a $41 million income tax adjustment, a $10 million gain on the sale of assets and an $8 million insurance premium surcharge. Net earnings in 2005 included a $17 million gain on the sale of assets and a $23 million insurance premium surcharge.

Refining and Supply contributed 2006 operating earnings adjusted for unusual items of $352 million, compared with $366 million in 2005. Lower 2006 operating earnings adjusted for unusual items reflected major planned turnarounds at the Edmonton and Montreal refineries and a fire at the Mississauga lubricants plant. These factors were partially offset by favourable realized refining margins.



Total sales of refined products decreased by less than 1%, compared with 2005. The reduced volumes were mainly due to lower furnace fuel oil sales as a result of warmer winter weather in Eastern Canada.

In 2006, marketing contributed operating earnings adjusted for unusual items of $78 million, compared with $55 million in 2005. Improved margins were partially offset by increased costs related to higher fuel prices.

Total Downstream operating, marketing, and general and administrative unit costs of 7.8 cents/litre in 2006 were up from 7.5 cents/litre in 2005. The increase mainly reflected increased shutdown costs, operating costs driven by higher energy prices and transportation costs, and one-time expenses incurred due to a fire at the Mississauga lubricants plant.

2006 OPERATING REVIEW AND STRATEGIC INITIATIVES

In 2006, the Downstream delivered record operating earnings for the third year in a row of $463 million due to a continued strong business environment and reliable operations at the Company's two refineries. With the major regulatory projects complete in 2006, Petro-Canada is well positioned with the supply capability to optimize profitability within a range of future business environment scenarios.

Refining and Supply

In 2006, the business processed an average of 37,800 m^3/d of crude oil, down from 40,900 m^3/d in 2005. The overall utilization rate at Petro-Canada's two refineries averaged 93% in 2006, down from 96% in 2005. The decline reflected planned major turnarounds at the Edmonton and Montreal refineries for maintenance and completion of the ultra-low sulphur diesel projects.

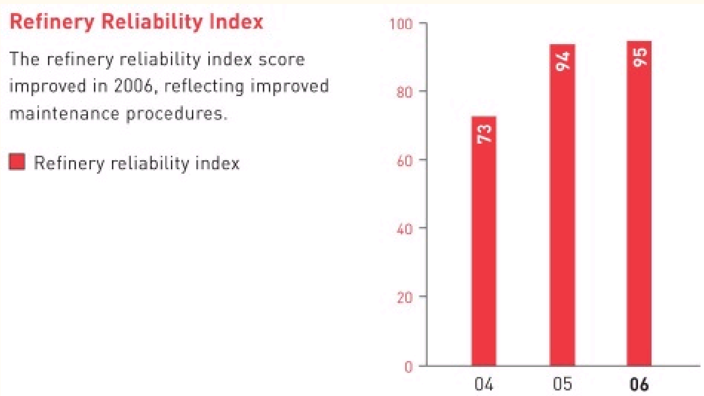
Overall plant reliability is a critical component of success in the refining business. For the second year in a row, strong operational performance at both refineries resulted in an overall reliability index of 95.

Work at the Montreal and Edmonton refineries to bring new diesel desulphurization units on-stream was completed on schedule in the second quarter of 2006.

Looking forward, Petro-Canada is well positioned to take advantage of the trend toward increased production of cheaper, heavier crudes. At the Edmonton refinery in 2006, the Company completed detailed engineering and started construction of new crude and vacuum units, and expanded coker and sulphur capacity. This was part of the refinery conversion project to upgrade and refine bitumen-based feedstock. The Edmonton refinery conversion project is estimated to cost $2 billion and come on-stream in 2008. At its Montreal refinery, the Company furthered work to evaluate the feasibility of adding a 25,000 b/d coker to the refinery. An investment decision on a new coker at the Montreal refinery is expected to be made in 2007.

Refinery Reliability Index

The refinery reliability index score improved in 2006, reflecting improved maintenance procedures.



Marketing

Total Downstream sales decreased to an average 52,500 m^3/d in 2006, compared with 52,800 m^3/d in 2005. Lower volumes were mainly due to a decline in furnace fuel oil sales as a result of warmer weather.

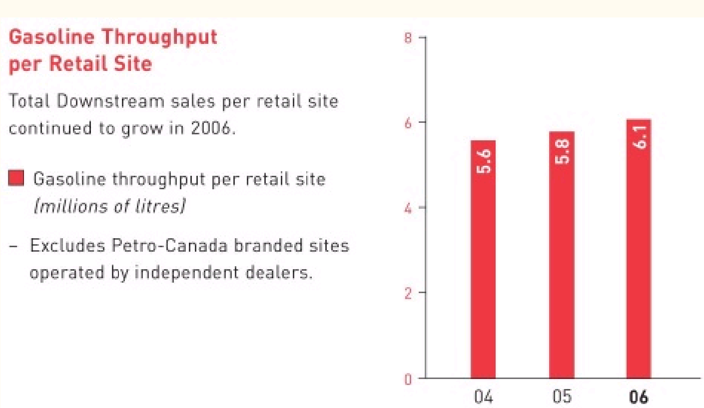
In the retail business, Petro-Canada completed most of its re-imaging program, contributing to industry-leading throughputs. Within the Company's network, annual gasoline sales from re-imaged sites averaged in excess of 7 million litres per site. The Company has extended the re-imaging program to independent retailers and, to date, nearly 62% of these retailers have chosen to participate.

Petro-Canada continued to leverage its position as "Canada's Gas Station." In 2006, the Company continued to focus on expanding its non-petroleum revenue base, as evidenced by the 8% year-over-year sales growth of its convenience store business and 5% increase in same-store sales, compared with 2005.

In 2006, the PETRO-PASS network, which includes 219 truck stop facilities, continued to be the leading national marketer of fuel in the commercial road transport segment in Canada. The distribution network was upgraded during the year.

Gasoline Throughput per Retail Site

Total Downstream sales per retail site continued to grow in 2006.

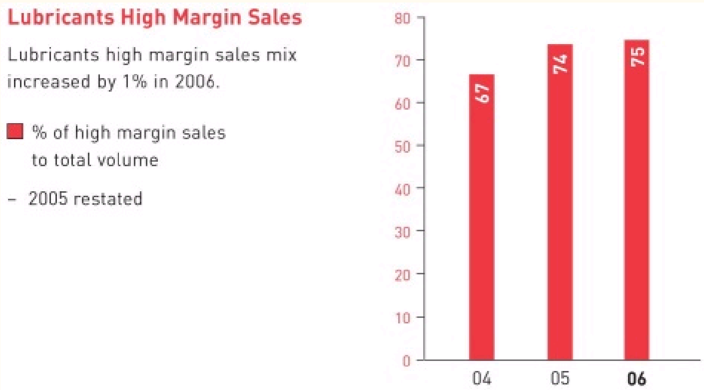


Lubricants

Overall sales of lubricants totalled 722 million litres in 2006, a decrease of 7% compared with sales volumes of 779 million litres in 2005. The decrease in sales volumes was primarily due to the impact of a fire at the lubricants facility early in 2006.

An investigation of the fire at the Mississauga lubricants plant indicated that the event occurred during a routine maintenance procedure in a fractionation section of the plant. Following the fire, the lubricants plant temporarily operated at 50% capacity. Repairs were completed and production on the unit was restored to pre-incident levels in March 2006. In June, the 25% expansion of the lubricants plant came on-stream. Sales in high margin product segments represented 75% of total sales, a 1% increase compared with 2005. Over the past five years, sales of high margin products have grown by approximately 26%.

Lubricants is positioned for profitable future growth as tougher performance and environmental standards increase global demand for higher quality base oils and finished products like those produced at the Mississauga lubricants plant.



OUTLOOK

Growth plans

- drive for first quartile refinery safety and reliability
- advance Edmonton refinery conversion project to process bitumen-based feedstock by 2008
- make investment decision for a coker at the Montreal refinery
- increase service station network effectiveness, with a focus on increasing non-petroleum revenue
- build wholesale volumes primarily through our commercial road transport and bulk fuels sales channels
- increase sales of high quality, higher margin lubricants

Capital spending plans in 2007

- approximately $1,075 million focused on new growth projects, such as the Edmonton refinery conversion and the possible Montreal coker
- approximately $125 million to enhance existing operations
- approximately $120 million to improve profitability in the base business
- approximately $70 million for regulatory compliance projects

Downstream capital spending shifts from regulatory requirements to growth in 2007, in particular with the conversion of the Edmonton refinery and an investment decision on a possible Montreal coker.

The Downstream business will have a capital program of approximately $1,390 million in 2007. The majority of capital spending is forecasted for new growth project funding of $1,075 million. This capital will be directed toward advancing the Edmonton refinery conversion project and completing the FEED on the 25,000 b/d Montreal coker in preparation for the 2007 investment decision.

Approximately $125 million is forecasted to be directed to the enhancement of existing operations. This includes reliability and safety improvements at Downstream facilities, as well as site enhancement within the wholesale and retail networks. A further $120 million is planned to be invested to improve the profitability of the Downstream's base business. This includes a number of high return refining projects and continued development of the retail and wholesale network.

Approximately $70 million is expected to be invested in regulatory compliance, down considerably from the $290 million invested in 2006. The majority of the 2006 regulatory compliance capital was required to produce cleaner burning diesel fuel.

Based on the current mid-cycle business environment, the Downstream business delivered a mid-cycle ROCE of more than 10% in 2006. Over time, it is anticipated that improvement in the base business and the refinery conversion projects will help drive the mid-cycle ROCE to the target of 12%.

Link to Petro-Canada's Corporate and Strategic Priorities

The Downstream business is aligned with Petro-Canada's strategic priorities as outlined by its progress in 2006 and goals for 2007.

	2006 RESULTS	2007 GOALS
Delivering Profitable Growth with a Focus on Operated, Long-Life Assets	▪ completed lubricant plant 25% expansion ▪ completed detailed engineering and 18% of the Edmonton refinery conversion project	▪ continue the Edmonton refinery conversion project to enable the planned startup in 2008 ▪ complete Montreal coker feasibility study for investment decision in 2007 ▪ continue to invest in smaller scale refinery yield and reliability improvement projects ▪ continue to integrate the Montreal refinery and the ParaChem Chemicals L.P. plant
Driving for First Quartile Operation of Our Assets	▪ achieved a combined reliability index of 95 at the Company's two refineries, above 90 for a second year in a row ▪ completed multi-year project to produce cleaner burning fuels at refineries ▪ maintained leading share of major retail urban market ▪ grew convenience store sales by 8% and same-store sales by 5%, compared with 2005 ▪ achieved 75% high margin lubricant sales volume mix	▪ continue to focus on safety and refinery reliability ▪ increase retail non-petroleum revenue ▪ grow high margin lubricants sales volume
Continuing to Work at Being A Responsible Comany	▪ reduced TRIF by 3%, compared with 2005 ▪ reduced regulatory compliance exceedances by 17%, compared with 2005	▪ maintain focus on TRIF and regulatory compliance exceedances ▪ meet provincial ethanol regulations ▪ continue focus on community relations, including establishment of Community Liaison Committee in Montreal ▪ continue to look for partnerships with Aboriginal communities on retail opportunities

Shared Services

Shared Services includes investment income, interest expense, foreign currency translation and general corporate revenue and expenses.

Shared Services Financial Results

(millions of Canadian dollars)	**2006**	2005	2004
Net loss	**$ (263)**	**$ (177)**	**$ (63)**
Loss on sale of assets	**-**	-	(1)
Foreign currency translation gain	**1**	73	63
Operating loss	**$ (264)**	**$ (250)**	**$ (125)**
Stock-based compensation	**(31)**	(66)	(11)
Income tax adjustments	**(71)**	(31)	(1)
Operating loss adjusted for unusual items	**$ (162)**	**$ (153)**	**$ (113)**
Cash flow from operating activities before changes in non-cash working capital	**$ (218)**	$ (225)	$ (106)

2006 COMPARED WITH 2005

Shared Services recorded an operating loss adjusted for unusual items of $162 million in 2006, compared with a loss of $153 million in 2005.

Shared Services net loss was $263 million in 2006, compared with a net loss of $177 million in 2005. The 2006 net loss included a $71 million charge for income tax adjustments and a $31 million charge related to the mark-to-market valuation of stock-based compensation. The 2005 net loss included a $73 million gain on foreign currency translation related to long-term debt, a $66 million charge related to the mark-to-market valuation of stock-based compensation and a $31 million charge related to income tax adjustments.

Financial Reporting

Critical Accounting Estimates

The preparation of the Company's financial statements requires management to adopt accounting policies that involve the use of significant estimates and assumptions. These estimates and assumptions are developed based on the best available information and are believed by management to be reasonable under the existing circumstances. New events or additional information may result in the revision of these estimates over time. The Audit, Finance and Risk Committee of the Board of Directors regularly reviews the Company's critical accounting policies and any significant changes thereto. A summary of the significant accounting policies used by Petro-Canada can be found in Note 1 to the 2006 Consolidated Financial Statements. The following discussion outlines what management believes to be the most critical accounting policies involving the use of significant estimates or assumptions.

Property, Plant and Equipment/Depreciation, Depletion and Amortization

Investments in exploration and development activities are accounted for under the successful efforts method. Under this method, the acquisition costs of unproved acreage; the costs of exploratory wells pending determination of proved reserves; and the costs of wells, which are assigned proved reserves and development costs, including costs of all wells, are capitalized. The cost of unsuccessful wells and all other exploration costs, including geological and geophysical costs, are charged to earnings as incurred. Capitalized costs of oil and gas producing properties are depreciated and depleted using the unit of production method based upon estimated reserves (see Estimated Oil and Gas Reserves discussion on page 42). Reserves estimates can have a significant impact on net earnings, because they are a key component in the calculation of depreciation and depletion related to the capitalized costs of property, plant and equipment. A revision in reserves estimates could result in a higher or lower depreciation and depletion charge to net earnings. A downward revision in reserves could result in a write-down of oil and gas producing properties as part of the impairment assessment (see Asset Impairment discussion below).

Asset Retirement Obligations

The Company currently records the obligation for estimated asset retirement costs at fair value when incurred. Factors that can affect the fair values of the obligations include the expected costs to be incurred, the useful lives of the assets and discount rates applied. Cost estimates are influenced by factors such as the number and type of assets subject to asset retirement obligations, the extent of work required and changes in environmental legislation. A revision to the estimated costs to be incurred, useful lives of the assets or discount rates applied could result in an increase or decrease in the total obligation, which would change the amount of amortization and accretion expense recognized in net earnings over time.

Asset Impairment

Producing properties and significant unproved properties are assessed annually, or as economic events dictate, for potential impairment. Impairment is assessed by comparing the estimated net undiscounted future cash flows to the carrying value of the asset. The cash flows used in the impairment assessment require management to make assumptions and estimates about recoverable reserves (see Estimated Oil and Gas Reserves discussion on page 42), future commodity prices and operating costs. Changes in any of the assumptions, such as a downward revision in reserves, a decrease in future commodity prices or an increase in operating costs, could result in an impairment of an asset's carrying value.

Purchase Price Allocation

Business acquisitions are accounted for by the purchase method of accounting. Under this method, the purchase price is allocated to the assets acquired and the liabilities assumed based on the fair value at the time of the acquisition. The excess purchase price over the fair value of identifiable assets and liabilities acquired is goodwill. The determination of fair value often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of property, plant and equipment acquired generally require the most judgment and include estimates of reserves acquired (see Estimated Oil and Gas Reserves discussion below), future commodity prices and discount rates. Changes in any of the assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to assets, liabilities and goodwill in the purchase price allocation. Future net earnings can be affected as a result of changes in future depreciation and depletion, asset impairment or goodwill impairment.

Goodwill Impairment

Goodwill is subject to impairment tests annually, or as economic events dictate, by comparing the fair value of the reporting unit to its carrying value, including goodwill. If the fair value of the reporting unit is less than its carrying value, a goodwill impairment loss is recognized as the excess of the carrying value of the goodwill over the fair value of the goodwill. The determination of fair value requires management to make assumptions and estimates about recoverable reserves (see Estimated Oil and Gas Reserves discussion below), future commodity prices, operating costs, production profiles and discount rates. Changes in any of these assumptions, such as a downward revision in reserves, a decrease in future commodity prices, an increase in operating costs or an increase in discount rates, could result in an impairment of all or a portion of the goodwill carrying value in future periods.

Estimated Oil and Gas Reserves

Reserves estimates, although not reported as part of the Company's Consolidated Financial Statements, can have a significant effect on net earnings as a result of their impact on depreciation and depletion rates, asset impairments and goodwill impairments (see discussion of these items above and on page 41). The Company's staff of qualified reserves evaluators performs internal evaluations on all of its oil and gas reserves on an annual basis using corporate-wide policies, procedures and practices. Independent qualified petroleum reservoir engineering consultants also conduct annual evaluations, technical audits and/or reviews of a significant portion of the Company's reserves and audit the Company's reserves policies, procedures and practices. In addition, the Company's contract internal auditors test the non-engineering management control processes used in establishing reserves. However, the estimation of reserves is an inherently complex process requiring significant judgment. Estimates of economically recoverable oil and gas reserves are based upon a number of variables and assumptions, such as geoscientific interpretation, economic conditions, commodity prices, operating and capital costs, and production forecasts, all of which may vary considerably from actual results. These estimates are expected to be revised upward or downward over time as additional information, such as reservoir performance, becomes available or as economic conditions change.

Employee Future Benefits

The Company maintains defined benefit pension plans and provides certain post-retirement benefits to qualifying retirees. The cost of pension and other post-retirement benefits are actuarially determined by an independent actuary using the projected benefit method, pro-rated based on service. The determination of these costs requires management to estimate or make assumptions regarding the expected plan investment performance, salary escalation, retirement ages of employees, expected health care costs, employee turnover and discount rates. Changes in these estimates or assumptions could result in an increase or decrease to the accrued benefit obligation and the related costs for both pensions and other post-retirement benefits.

Income Taxes

The Company follows the liability method of accounting for income taxes, whereby future income taxes are recognized based on the differences between the carrying amounts of assets and liabilities reported in the financial statements and their respective tax bases. The determination of the income tax provision is an inherently complex process requiring management to interpret continually changing regulations and to make certain judgments. While income tax filings are subject to audits and reassessments, management believes adequate provision has been made for all income tax obligations. However, changes in the interpretations or judgments may result in an increase or decrease in the Company's income tax provision in the future.

Contingencies

The Company is involved in litigation and claims in the normal course of operations. Management is of the opinion that any resulting settlements would not materially affect the financial position of the Company as at December 31, 2006. However, the determination of contingent liabilities relating to litigation and claims is a complex process that involves judgments as to the outcomes and interpretation of laws and regulations. Changes in the judgments or interpretations may result in an increase or decrease in the Company's contingent liabilities in the future.

SHARE DATA

The authorized share capital of Petro-Canada consists of an unlimited number of common shares and an unlimited number of preferred shares issuable in series designated as either senior preferred shares or junior preferred shares. As at March 1, 2007, there were 497,132,045 common shares outstanding and no preferred shares outstanding. For details of the Company's share capital and stock options outstanding at December 31, 2006, refer to Notes 21 and 22 of the 2006 Consolidated Financial Statements.

ADDITIONAL INFORMATION

Copies of this MD&A and the following Consolidated Financial Statements, as well as the Company's latest AIF and Management Proxy Circular, may be obtained from the Company's website at www.petro-canada.ca or by mail upon request from the Corporate Secretary, 150 - 6 Avenue S.W., Calgary, Alberta, T2P 3E3. Other disclosure documents, and any reports, statements or other information filed by Petro-Canada with the Canadian provincial securities commissions or other similar regulatory authorities, are accessible through the Internet on the Canadian System for Electronic Document Analysis and Retrieval, which is commonly known by the acronym SEDAR, and located at www.sedar.com. SEDAR is the Canadian equivalent of the U.S. SEC's Electronic and Document Gathering and Retrieval System, which is commonly known by the acronym EDGAR, and located at www.sec.gov.

Exhibit 99.3

CERTIFICATION PURSUANT TO SECTION 302 OF SARBANES-OXLEY ACT

I, Ronald A. Brenneman, certify that:

1. I have reviewed this annual report on Form 40-F of Petro-Canada;

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

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

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

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

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

Date: March 29, 2007

/s/ Ronald A. Brenneman
Ronald A. Brenneman
President and Chief Executive Officer

Exhibit 99.4

CERTIFICATION PURSUANT TO SECTION 302 OF SARBANES-OXLEY ACT

I, E. F. H. Roberts, certify that:

1. I have reviewed this annual report on Form 40-F of Petro-Canada;

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

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

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

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

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

Date: March 29, 2007

/s/ E. F. H. Roberts
E. F. H. Roberts
Executive Vice-President and
Chief Financial Officer

Exhibit 99.5

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

In connection with the annual report of Petro-Canada (the "Company") on Form 40-F for the fiscal year ending December 31, 2006 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Ronald A. Brenneman, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

Date: March 29, 2007

/s/ Ronald A. Brenneman
Ronald A. Brenneman
President and Chief Executive Officer

Exhibit 99.6

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

In connection with the annual report of Petro-Canada (the "Company") on Form 40-F for the fiscal year ending December 31, 2006 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, E. F. H. Roberts, Executive Vice-President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

Date: March 29, 2007

/s/ E.F.H. Roberts
E. F. H. Roberts
Executive Vice-President and
Chief Financial Officer

Exhibit 99.7

CONSENT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

We consent to the incorporation by reference in the following Registration Statements:

- Registration Statement No. 333-126045 on Form S-8;
- Registration Statement No. 333-100973 on Form S-8

and to the use of our reports dated February 12, 2007 relating to the consolidated financial statements of Petro-Canada and management’s report on the effectiveness of internal control over financial reporting (which report on the consolidated financial statements expressed an unqualified opinion and includes a separate report titled Comments by Independent Registered Chartered Accountants on Canada - United States of America Reporting Difference referring to changes in accounting principles that have a material effect on the comparability of the financial statements), appearing in Annual Report on Form 40-F of Petro-Canada for the year ended December 31, 2006.

Deloitte & Touche LLP

Independent Registered Chartered Accountants
Calgary, Canada
February 12, 2007