2005 Quarterly Report

PETRO-CANADA

For immediate release
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Strong Cash Position Supports Larger Capital Budget and More Cash To Shareholders

Highlights

- 33% increase to quarterly dividend and renewal of share repurchase program
- Capital program increased to $3.6 billion to fund additional growth opportunities

Calgary – Petro-Canada announced today second quarter earnings from operations adjusted for unusual items of $525 million ($2.02/share), up 8% from $485 million ($1.82/share) in the same quarter of 2004. Second quarter 2005 cash flow was $934 million ($3.60/share), compared with $856 million ($3.22/share) in the same quarter of last year. Cash flow is before changes in non-cash working capital.

Net earnings for the second quarter in 2005 were $345 million ($1.33/share), compared with $393 million ($1.48/share) in the same period of 2004. Net earnings include unrealized gains or losses on derivative contracts, together with gains or losses on foreign currency translation and disposal of assets. In the second quarter of 2005, an unrealized mark-to-market loss on derivative contracts associated with the Buzzard acquisition lowered net earnings by $171 million after-tax.

“Solid operating results and a strong business environment generated additional cash flow. We used our financial position to increase the capital program and return more cash to shareholders,” said Ron Brenneman, president and chief executive officer.

The Company announced a 33% increase to the quarterly dividend and a stock dividend. The stock dividend doubles the number of shares outstanding and effectively achieves a two-for-one stock split. In June, Petro-Canada renewed its normal course issuer bid for the repurchase of its common shares.

Production of crude oil, natural gas liquids and natural gas averaged 420,100 barrels of oil equivalent/day (boe/d) during the quarter. Production for the full year is expected to be 415,000 – 430,000 boe/d, in line with previous guidance.

“We came one step closer to adding near-term production growth with the successful startup of Pict in the North Sea,” said Brenneman. “With White Rose expected on-stream around year end, and the Syncrude expansion and Buzzard project on schedule for next year, we are building our production profile.”

Petro-Canada is one of Canada’s largest oil and gas companies, operating in both the upstream and downstream sectors of the industry in Canada and internationally. Its common shares trade on the Toronto Stock Exchange under the symbol PCA and on the New York Stock Exchange under the symbol PCZ.

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MANAGEMENT'S DISCUSSION AND ANALYSIS

The Management's Discussion and Analysis (MD&A), dated July 26, 2005, is set out in pages 2 to 16 and should be read in conjunction with: the unaudited Consolidated Financial Statements for the three months ended March 31, 2005 and the six months ended June 30, 2005; the MD&A for the three months ended March 31, 2005 and the year ended December 31, 2004; the audited Consolidated Financial Statements for the year ended December 31, 2004; and the 2004 Annual Information Form dated March 15, 2005.

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. Earnings from operations, which represent net earnings excluding gains or losses on foreign currency translation, disposal of assets and unrealized gains or losses on the mark-to-market of the derivative contracts associated with the Buzzard acquisition, are used by the Company to evaluate operating performance. Cash flow and earnings from operations do not have a standardized meaning prescribed by Canadian generally accepted accounting principles (GAAP) and, therefore, may not be comparable with the calculation of similar measures for other companies. For reconciliations of the cash flow and earnings from operations amounts to the associated GAAP measure, refer to the tables on page 16 of the MD&A.

BUSINESS ENVIRONMENT

Market prices shown below influence average prices realized for crude oil, natural gas liquids (NGL), natural gas and petroleum products shown in the table on page 14.

In the second quarter of 2005, the price of Dated Brent averaged $51.59 US/barrel (bbl), up 46% from $35.36 US/bbl in the second quarter of 2004. During the same period of 2005, the Canadian dollar averaged $0.80 US, up 8% from $0.74 US in the second quarter of 2004. The net impact of these two changes was a 29% increase in Petro-Canada's corporate-wide realized Canadian dollar prices for crude oil and liquids, from $46.52/bbl in the second quarter of 2004 to $59.85/bbl in the second quarter of 2005.

The increase in international and domestic light crude prices was accompanied by a substantial widening in international and Canadian light/heavy crude price differentials. In the second quarter, the spread between Dated Brent and Mexican Maya widened to $11.60 US/bbl, compared with $5.76 US/bbl in the second quarter of 2004. In Canada, the spread between Edmonton Light and Lloydminster Blend widened to $26.99/bbl in the second quarter of 2005, compared with $14.91/bbl in the second quarter of 2004.

In the second quarter of 2005, Henry Hub natural gas prices averaged $6.80 US/million British thermal units (MMBtu), compared with $5.97 US/MMBtu in the second quarter of 2004. In the same period, AECO natural gas prices averaged $7.69/thousand cubic feet (Mcf), up 9% compared to the average of $7.09/Mcf during the second quarter of 2004. Petro-Canada's realized Canadian dollar prices for its North American Natural Gas business averaged $7.24/Mcf in the second quarter of 2005 compared with $6.91/Mcf in the second quarter of 2004.

During the second quarter, the New York Harbour 3-2-1 refinery crack spreads averaged $8.42 US/bbl, slightly down from $8.89 US/bbl in the second quarter of 2004. In the Downstream business, the effect of marginally weaker refining spreads was partially offset by wider light/heavy crude price differentials.

The average market prices for the three months and six months ended June 30 were:

	Three months ended June 30,		Six months ended June 30,	
(average for the period)	2005	2004	2005	2004
Dated Brent at Sullom Voe *US$/bbl*	51.59	35.36	49.55	33.66
West Texas Intermediate (WTI) at Cushing *US$/bbl*	53.17	38.32	51.51	36.73
Dated Brent-Maya FOB price differential *US$/bbl*	11.60	5.76	13.24	5.92
Edmonton Light *Cdn$/bbl*	66.42	50.82	64.14	48.29
Edmonton Light/Lloydminster Blend FOB price differential *Cdn$/bbl*	26.99	14.91	26.08	14.07
Natural gas at Henry Hub *US$/MMBtu*	6.80	5.97	6.56	5.83
Natural gas at AECO *Cdn$/Mcf*	7.69	7.09	7.33	6.99
New York Harbour 3-2-1 crack spread *US$/bbl*	8.42	8.89	7.21	7.92
Exchange rate *US cents/Cdn$*	80.4	73.6	80.9	74.7

The following table shows the estimated after-tax effects that changes in certain factors would have had on Petro-Canada's 2004 net earnings had these changes occurred. Amounts are stated in Canadian dollars unless otherwise specified.

Factor (1), (2)	**Change (+)**	**Annual net earnings impact** *(millions of dollars)*	**Annual net earnings impact** *($/share)*
Upstream			
Price received for crude oil and NGL(3)	$1.00/bbl	$ 45	$ 0.17
Price received for natural gas	$0.25/Mcf	33	0.12
Exchange rate: Cdn$/US$ refers to impact on upstream earnings from operations (4)	$0.01	(22)	(0.08)
Crude oil and NGL production	1,000 b/d	5	0.02
Natural gas production	10 MMcf/d	9	0.03
Downstream			
New York Harbour 3-2-1 crack spread	$0.10 US/bbl	4	0.02
Light/heavy crude price differential	$1.00/bbl	11	0.04
Corporate			
Exchange rate: Cdn$/US$ refers to impact of the revaluation of U.S. dollar denominated, long-term debt (5)	$0.01	$ 9	$ 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) This sensitivity is based upon an equivalent change in the price of WTI and Dated Brent.

(4) A strengthening Canadian dollar versus the United States (U.S.) dollar has a negative effect on upstream earnings.

(5) A strengthening Canadian dollar versus the U.S. dollar has a positive effect on corporate earnings. The impact refers to gains or losses on $869 million US of the Company's U.S. denominated long-term debt and interest costs on U.S. denominated debt. Gains or losses on $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.

ANALYSIS OF CONSOLIDATED EARNINGS AND CASH FLOW

Earnings Analysis

	Three months ended June 30,				Six months ended June 30,			
($ millions, except per share amounts)	**2005**	**($/share)**	**2004**	**($/share)**	**2005**	**($/share)**	**2004**	**($/share)**
Net earnings	**$ 345**	**$ 1.33**	**$ 393**	**$ 1.48**	**$ 463**	**$ 1.78**	**$ 906**	**$ 3.41**
Foreign currency translation	8		(21)		4		(34)	
Unrealized loss on Buzzard derivative contracts	(171)		(57)		(484)		(57)	
Gain on asset sales	9		–		9		9	
Earnings from operations	**499**	**1.92**	**471**	**1.77**	**934**	**3.59**	**988**	**3.72**
Stock-based compensation	(11)		(1)		(22)		(3)	
Insurance premium surcharges (1)	(15)		–		(35)		–	
Oakville closure costs	–		(13)		(1)		(26)	
Income tax adjustment	–		–		–		13	
Terra Nova insurance proceeds	–		–		–		31	
Earnings from operations adjusted for unusual items	**$ 525**	**$ 2.02**	**$ 485**	**$ 1.82**	**$ 992**	**$ 3.82**	**$ 973**	**$ 3.66**

(1) Insurance premium surcharges include an accrual for Oil Insurance Ltd. (OIL) and sEnergy Insurance Ltd. policies. OIL is a mutual insurance company that was formed to insure against catastrophic risks. sEnergy Insurance Ltd. is a provider of business interruption and excess property insurance to the energy industry.

Foreign currency translation reflects gains or losses on U.S. dollar denominated long-term debt that is not associated with the self-sustaining International business unit and the U.S. Rockies operations included in the North American Natural Gas business unit. In June 2004, as part of its acquisition of an interest in the Buzzard field in the United Kingdom (U.K.) sector of the North Sea, the Company entered into derivative contracts for half of its share of estimated production for the first 3 1/2 years. Buzzard unrealized mark-to-market losses are recorded each quarter because these transactions do not currently qualify for hedge accounting.

Earnings Variances

Earnings from operations adjusted for unusual items in the second quarter of 2005 were $525 million ($2.02/share), compared with $485 million ($1.82/share) in the second quarter of 2004. The increase in second quarter earnings reflects higher realized commodity prices partially offset by lower upstream volumes and downstream margins, higher operating costs and a stronger Canadian dollar.

In the second quarter of 2005, earnings from operations included unusual charges of $11 million related to the mark-to-market of stock-based compensation and $15 million related to an insurance premium accrual. The insurance premium accrual was reflected in operating costs and represents incremental costs associated with Petro-Canada's allocated share of five-year losses, previously incurred with the insurance pools of OIL and sEnergy policies, and will be paid in future premiums. In the second quarter of 2004, earnings from operations included unusual charges of $13 million related to the consolidation of the Eastern Canada refinery operations and $1 million related to stock-based compensation.

Consolidated six month earnings from operations adjusted for unusual items were $992 million ($3.82/share), compared to $973 million ($3.66/share) in the same period of 2004. Higher realized commodity prices were offset by lower upstream volumes and realized prices for bitumen, higher operating and exploration costs, and a stronger Canadian dollar.

During the second quarter of 2005, cash flow was $934 million ($3.60/share), up from $856 million ($3.22/share) in the same quarter of 2004.

UPSTREAM

Production

Petro-Canada converts gas to oil equivalent at a rate of 6 Mcf of gas to one bbl of oil. Production volumes disclosed are net working interest before royalties, unless otherwise specified.

In the second quarter of 2005, production of crude oil, NGL and natural gas averaged 420,100 boe/d, compared with 455,200 boe/d in the second quarter of 2004. Higher production from Oil Sands and acquired U.S. Rockies volumes were more than offset by natural declines in International production, compression issues at Terra Nova and planned maintenance turnarounds in North American Natural Gas.

2005 Consolidated Production Outlook

Upstream production is expected to average between 415,000 to 430,000 boe/d in 2005, in line with previous guidance. Stronger International production is expected to offset lower MacKay River production, extended turnarounds at Terra Nova and Syncrude, and lower than expected Terra Nova reliability. Factors that may impact production during the remainder of 2005 include reservoir performance, drilling results, facility reliability and the startup of White Rose.

	2005 Outlook (+/-)	**2005 Outlook (+/-)**
(thousands of boe/d)	**As at July 26, 2005**	**As at December 16, 2004**
North American Natural Gas		
– Natural gas	113	113
– Liquids	14	14
East Coast Oil	75	77
Oil Sands		
– Syncrude	26	28
– MacKay River	21	24
International		
– North Africa/Near East	115	114
– Northwest Europe	45	43
– Northern Latin America	12	11
Total	415 - 430	415 - 440

North American Natural Gas

North American Natural Gas production remains on track with full year guidance. Increased focus on unconventional gas plays, land acquisitions in the far north and progress on the proposed Quebec liquefied natural gas project position the business for the future.

In the second quarter of 2005, North American Natural Gas contributed $117 million of earnings from operations adjusted for unusual items, compared with $133 million in the second quarter of 2004. Stronger realized prices and production from the U.S. Rockies acquisition were more than offset by lower Western Canada volumes, increased operating costs and higher depreciation, depletion and amortization.

Increased operating costs in the second quarter of 2005 reflected incremental operating costs from the U.S. Rockies and rising industry costs.

Net earnings from North American Natural Gas were $117 million, down from $133 million in the second quarter of 2004.

Natural gas commodity prices remained strong in the second quarter of 2005. Western Canada realized natural gas prices averaged $7.33/Mcf, up from $6.91/Mcf in the same quarter of 2004. U.S. Rockies realized natural gas prices converted to Canadian dollars averaged $6.66/Mcf in the second quarter of 2005.

In the second quarter of 2005, North American Natural Gas production averaged 741 million cubic feet/day of natural gas equivalent (MMcfe/d), compared with 773 MMcfe/d in the same period last year. Scheduled maintenance activities at Petro-Canada operated natural gas processing facilities proceeded as planned. Maintenance at partner-operated facilities took longer than planned. In total, these maintenance activities reduced production by about 40 MMcf/d in the second quarter of 2005. Scheduled maintenance activities at Petro-Canada's facilities are expected to impact production by approximately 10 MMcf/d in the third quarter of 2005.

Far North

In the second quarter, Petro-Canada and Anadarko Petroleum Corporation increased their joint land position from 1.5 million to 2.5 million acres in the gas prospective North Slope region of the Brooks Range in Alaska. Petro-Canada's working interest averages 40% in those lands. In the Mackenzie Delta/Corridor, Petro-Canada acquired two exploration licences, amounting to 166,000 hectares and a work commitment of approximately $35 million.

East Coast Oil

East Coast Oil delivered strong earnings and cash flow during the second quarter of 2005. Plans are in place to further improve Terra Nova reliability in the second half of the year.

In the second quarter of 2005, East Coast Oil contributed $213 million of earnings from operations adjusted for unusual items, up 17% from $182 million in the second quarter of 2004. Stronger realized prices were partially offset by lower production at Terra Nova and Hibernia, increased operating costs, and higher depreciation, depletion and amortization.

Net earnings from East Coast Oil were $208 million, up from $182 million in the second quarter of 2004. Net earnings in the second quarter of 2005 included a $5 million charge related to an insurance premium surcharge. Increased operating costs in the second quarter of 2005 are primarily due to this insurance premium surcharge.

During the second quarter of 2005, East Coast Oil realized crude prices averaged $61.41/bbl, compared with $47.51/bbl in the second quarter of 2004.

In the same period, production averaged 77,800 b/d, compared with 85,400 b/d during the second quarter of 2004. Terra Nova's second quarter production averaged 38,100 b/d, compared with 41,900 b/d in the second quarter of 2004. Production at Terra Nova in June was impacted by issues with the gas compression system. Hibernia delivered steady reliability with production averaging 39,700 b/d during the second quarter of 2005. In the same quarter of 2004, Hibernia production averaged 43,500 b/d, reflecting exceptional reliability.

Scheduled Turnarounds

In early September 2005, Terra Nova is scheduled to shut down for a planned turnaround, which has been extended from 30 to 40 days. The gas compression system will be down for an additional 10 days. The turnaround will include regulatory inspections on equipment, and modifications to improve the reliability of the gas compression and injection systems. Petro-Canada is taking a staged approach to achieve first quartile reliability at Terra Nova, with a second phase of repairs to occur in 2006.

During the third quarter of 2005, a six-day turnaround is scheduled at Hibernia.

Terra Nova Royalty Rate

As expected, royalties at Terra Nova will increase late this year, reflecting the provincial profit-sensitive royalty regime. In the fourth quarter of 2005, it is expected Terra Nova will be subject to the incremental royalty regime. This will have the effect of increasing royalties from 5% of gross revenues to approximately 24% of gross revenues.

Other East Coast Oil Offshore

Construction of the White Rose facility continues to progress on budget and on schedule for startup around year end. At the end of the second quarter, atshore commissioning of the final floating production, storage and offloading (FPSO) systems were well underway and the installation of the remaining subsea facilities required for first oil had commenced. White Rose is expected to produce an average of 25,000 b/d of peak production net to Petro-Canada when fully operational.

Oil Sands

Highlights in the quarter include strong reliability at MacKay River and signing of the Fort Hills formal partnership agreement.

Oil Sands contributed $35 million of earnings from operations adjusted for unusual items in the second quarter of 2005, up from $25 million in the second quarter of 2004. Higher realized prices at Syncrude and increased MacKay River and Syncrude production were partially offset by the impact of widening light/heavy crude price differentials on bitumen prices, and higher depreciation, depletion and amortization and operating costs.

Increased operating costs were primarily due to higher diluent purchases associated with increased MacKay River production.

In the second quarter of 2005, Oil Sands net earnings were $34 million, up from net earnings of $25 million in the second quarter of 2004. Net earnings in the second quarter of 2005 included a $1 million charge related to an insurance premium surcharge.

Syncrude production stabilized to normal levels during the second quarter after completion of turnaround activities. Production averaged 28,000 b/d in the second quarter of 2005, compared with 27,500 b/d in the second quarter of 2004. Syncrude realized prices averaged $67.08/bbl, up from $51.41/bbl in the second quarter of 2004. In September 2005, a planned turnaround of the vacuum distillation unit has been extended from 45 to 52 days. The turnaround allows Syncrude to tie-in this unit to the Stage III expansion.

Reliability improved and production continued to increase at MacKay River during the second quarter of 2005. Production averaged 20,900 b/d in the second quarter, up from 13,200 b/d in the same period of 2004. Work to tie-in the new well pad will continue until year end, contributing to targeted production of 27,000 to 30,000 b/d by mid-2006. MacKay River bitumen realized prices averaged $13.92/bbl in the second quarter of 2005, compared with $19.61/bbl in the second quarter of 2004.

Fort Hills

On June 24, 2005, Petro-Canada signed the Fort Hills formal partnership and unanimous shareholder agreements with UTS Energy Corporation. Currently, Petro-Canada is in the first phase of work on engineering and investigation of options for the mine, extraction and upgrading. By year end, Petro-Canada expects to start the design basis memorandum, which establishes key design parameters and the project schedule. Petro-Canada is a 60% interest holder and operator of the Fort Hills oil sands mining and upgrading project, with leases estimated to contain 1.7 billion bbls of bitumen resource net to Petro-Canada.

International

The International business continued to enhance its portfolio during the second quarter, achieving first oil at Pict, realizing exploration success in the North Sea and acquiring exploration blocks in Trinidad and Tobago.

International contributed $121 million of earnings from operations adjusted for unusual items in the second quarter of 2005, compared with $72 million in the second quarter of 2004. Stronger realized commodity prices were partially offset by lower production in Northwest Europe and North Africa/Near East.

In the second quarter of 2005, International had a net loss of $55 million, compared with net earnings of $15 million in the second quarter of 2004. The net loss in the second quarter of 2005 included a $171 million unrealized loss on the Buzzard derivative contracts and a $5 million charge related to an insurance premium surcharge. Net earnings in the second quarter of 2004 included a $57 million unrealized loss on the Buzzard derivative contracts. Increased operating costs in the second quarter of 2005 were primarily due to an insurance premium surcharge.

International realized commodity prices remained strong during the second quarter of 2005. International crude oil and NGL realized prices averaged $64.62/bbl, compared with $47.44/bbl in the same period of 2004. International realized prices for natural gas averaged $5.99/Mcf in the second quarter of 2005, compared with $5.14/Mcf in the same period of 2004.

During the second quarter, International production averaged 169,900 boe/d, compared with 200,300 boe/d in the second quarter of 2004 due to lower production in the North Sea and Syria. Initiatives are underway to steadily increase International production, with several advancements occurring in the quarter.

Northwest Europe

Second quarter production averaged 36,400 boe/d, down from 57,900 boe/d in the same period last year. Production from the U.K. sector of the North Sea averaged 22,000 boe/d in the second quarter of 2005, down compared with 36,200 boe/d in the same period last year. Lower production was due to natural declines, a maintenance turnaround at the Scott platform and shut-ins at Guillemot West to allow Pict tie-in work. The Scott platform turnaround was accelerated from the third quarter of 2005 and will be completed in late July. Production in The Netherlands sector of the North Sea averaged 14,500 boe/d in the second quarter of 2005, compared with 21,700 boe/d in the second quarter of 2004. Lower Netherlands production was due to natural declines.

In the third week of June 2005, Petro-Canada's Pict development, located in block 21/23b in the U.K. Central North Sea, achieved first oil. One hundred per cent owned and operated by Petro-Canada, the Pict field is estimated to have resources of about 15 million barrels of oil. The Pict field was developed with sub-sea facilities tied back to the Triton FPSO via the Guillemot West and Northwest infrastructure. Pict is expected to produce an average of 15,000 boe/d for the remainder of this year and 10,000 boe/d in 2006.

Buzzard Development

The next U.K. North Sea development to come on-stream is the Buzzard field, in which Petro-Canada has a 29.9% interest. Progress on the Buzzard field development continues on schedule and on budget, with 70% of the construction complete. First oil is expected near the end of 2006, with peak production of 60,000 boe/d net to Petro-Canada expected in late 2007.

Other Developments

The De Ruyter development, located in the Dutch sector of the North Sea, is expected to be on-stream in late 2006, with peak production of 10,000 boe/d net to Petro-Canada.

During the first half of the year, Petro-Canada made two discoveries in the U.K. sector of the North Sea and progressed work on the Hejre discovery. Petro-Canada has a 100% working interest in the Saxon discovery in the Triton area. Saxon is estimated to be similar in size to the Pict field and could be on-stream sometime in 2007. A second discovery has been made in block 13/27a, which is located 40 kilometres northwest of the Buzzard field. Analysis is currently underway to determine if additional appraisal is warranted to establish commercial viability. In Denmark, work progressed on the previously discovered Hejre field, in which Petro-Canada has a 25% working interest. A successful appraisal well is currently being evaluated with a view to implementing a phased production scheme starting in 2009.

North Africa/Near East

Production in North Africa/Near East averaged 121,100 boe/d in the second quarter of 2005, down from 130,600 boe/d in the same quarter of 2004. Libyan production averaged 49,700 b/d, compared with 49,500 b/d in the second quarter of 2004. Fire damage to process equipment in mid-June will negatively impact Libyan production by approximately 5,500 b/d in the third quarter of 2005. Syrian production averaged 71,400 boe/d, down from 80,600 boe/d as a result of natural declines in the existing mature fields.

On July 6, 2005, Petro-Canada signed a one-year reconnaissance licence with the Moroccan Office National Bureau for Hydrocarbons and Mines. The Company will carry out field work and studies in the Bas Draa block (covering 59,000 square kilometres) during the reconnaissance licence period.

Northern Latin America

Trinidad offshore gas production averaged 74 MMcf/d in the second quarter of 2005, compared with 71 MMcf/d in the second quarter of 2004.

On July 5, Petro-Canada signed production sharing contracts with the Trinidad and Tobago Ministry of Energy and Energy Industries for offshore exploration blocks 1a, 1b and 22. These blocks cover 4,258 square kilometres, with block 1a containing four discoveries. The Company will invest approximately $100 million in the first phase of exploration, which includes shooting 3D seismic and drilling six exploration wells. Plans are well advanced to begin shooting the seismic on blocks 1a and 1b in the fourth quarter of 2005.

DOWNSTREAM

Successful completion of the Eastern Canada refinery consolidation and two major refinery turnarounds were highlights in the quarter. Higher crude prices and intense competition lowered marketing margins in the Downstream business.

The Downstream business contributed $84 million of earnings from operations adjusted for unusual items in the second quarter of 2005, down from $105 million in the same quarter of 2004. The decrease in earnings from operations reflected weaker gasoline cracking and asphalt margins, the impact of planned refinery turnarounds, and lower production and sales volumes resulting from the Eastern Canada consolidation. These factors were partially offset by wider light/heavy crude price differentials and higher distillate cracking margins.

The Downstream business recorded second quarter net earnings of $89 million, compared with net earnings of $92 million in the same quarter of 2004. Second quarter 2005 net earnings included a $9 million gain on the sale of assets and a $4 million charge related to an insurance premium surcharge. Net earnings in the second quarter of 2004 included a $13 million charge related to the consolidation of Eastern Canada refinery operations.

The average New York Harbour 3-2-1 refinery crack spread was $8.42 US/bbl in the second quarter of 2005, down from $8.89 US/bbl in the second quarter of 2004. The impact was exacerbated by a stronger Canadian dollar. The average international light/heavy crude price differential widened to $11.60 US/bbl in the second quarter of 2005, compared with $5.76 US/bbl in 2004.

In the second quarter of 2005, total sales of refined petroleum products were down 10%, compared with the same period last year. The reduced volumes resulted mainly from lower sales of asphalt, heavy fuel oil and jet fuel associated with the consolidation of Eastern Canada refinery operations.

Refining and supply contributed second quarter 2005 earnings from operations adjusted for unusual items of $76 million, compared with $90 million in the same quarter of 2004. Results were impacted by lower gasoline cracking and asphalt margins, planned refinery shutdowns and lower volumes due to the Eastern Canada consolidation. These factors were partially offset by wider light/heavy crude differentials and higher distillate cracking margins.

Marketing contributed second quarter 2005 earnings from operations adjusted for unusual items of $8 million, compared with $15 million in the same quarter of 2004. Retail marketing margins were weak due to rising crude costs and intense competition in several major markets.

Eastern Canada Consolidation

With the conversion of the Oakville refinery to a terminal in April 2005, Petro-Canada successfully consolidated its Eastern Canada refinery operations. The Ontario market is now supplied via the Trans Northern Pipelines Inc. pipeline from the expanded Montreal refinery and from new gasoline, diesel and feedstock supply contracts.

Petrochemical Facility

Integration activities between the Montreal refinery and the Coastal Petrochemical (Coastal) paraxylene facility are underway as a result of Petro-Canada acquiring a 51% interest in March 2005. This partnership allows Petro-Canada to pursue incremental business opportunities that build on the strengths of its newly consolidated Eastern Canada refining and supply hub.

Downstream Turnaround Activity

Two major refinery turnarounds, a 30-day turnaround in Montreal and a 25-day crude unit turnaround in Edmonton, were completed on time and on budget in the second quarter of 2005. During the third quarter of 2005, a 33-day turnaround at the Mississauga lubricants plant and a 35-day hydrocracker turnaround at the Montreal refinery are planned.

CORPORATE

Shared Services recorded a net loss of $48 million in the second quarter of 2005, compared with a net loss of $54 million for the same period in 2004. The second quarter 2005 net loss included an $11 million charge related to the mark-to-market of stock-based compensation and an $8 million gain on foreign currency translation related to long-term debt. The second quarter 2004 net loss included a $21 million loss on foreign currency translation related to long-term debt.

Interest expense during the second quarter of 2005 was $39 million before-tax, compared with $38 million before-tax in the prior year, as interest associated with higher levels of debt was offset by higher capitalized interest.

Cash flow was affected by two items that typically cause differences between earnings and cash flow. Tax deferrals resulting from the Company's upstream partnership increased cash flow by about $45 million in the quarter, compared with a decrease of $10 million in the same period last year. The inventory valuation method prescribed for income tax purposes in the Downstream business decreased second quarter cash flow by approximately $27 million, compared with a decrease of $24 million in 2004.

Shareholder Activities

Normal Course Issuer Bid (NCIB) Renewed

Petro-Canada's priority uses of cash are to fund the capital program and profitable growth opportunities, and to return cash to shareholders through dividends and share buybacks. During the second quarter of 2005, Petro-Canada purchased a total of 1,021,800 common shares at an average price of $74.01/share for a total cost of approximately $75 million. Under the NCIB, which was effective from June 22, 2004 to June 21, 2005, the Company purchased a total of 8,674,782 common shares at an average price of $66.39/share for a total cost of approximately $576 million. Petro-Canada renewed its NCIB for the repurchase of its common shares from June 22, 2005 to June 21, 2006, entitling the Company to purchase up to 5% of the outstanding common shares, subject to certain conditions.

Stock Dividend

On July 26, 2005, the Board of Directors declared a stock dividend which will double the number of shares outstanding and effectively achieve a two-for-one stock split. The stock dividend is payable on September 14, 2005 to common shareholders of record at the close of business on September 3, 2005, with one additional common share being issued for each outstanding common share held.

Dividend Increased 33%

Commencing with the fourth quarter dividend to be paid on October 1, 2005, the Company will increase the quarterly dividend 33%, from $0.15/share to $0.20/share on a pre-stock dividend basis ($0.10/share on a post-stock dividend basis). Petro-Canada regularly reviews its dividend strategy to ensure the alignment of dividend policy with shareholder expectations, and financial and growth objectives.

Accounting Changes

Effective January 1, 2005, the Company changed the presentation of cash flow in the Consolidated Statement of Cash Flows pursuant to recent interpretations from the U.S. Securities and Exchange Commission (SEC). Previously, all exploration expenses were classified as investing activities. With the change, general and administrative and geological and geophysical exploration expenses are treated as a reduction of cash flow from operating activities. All prior periods have been restated to reflect this change. The change results in a decrease in cash flow from operating activities and an increase in cash flow from investing activities by $35 million for the three months ended June 30, 2005.

LIQUIDITY AND CAPITAL RESOURCES

At June 30, 2005, the balance of short-term debt outstanding was $24 million, consisting of amounts outstanding on bilateral demand credit facilities. This balance was repaid from cash on hand after the end of the second quarter.

Petro-Canada's syndicated committed credit facilities totaled $1,500 million at the end of the quarter. The Company also had bilateral demand credit facilities of $423 million. At June 30, 2005, a total of $1,090 million of the credit facilities was used for letters of credit and overdraft coverage. The syndicated facilities also provide liquidity support to Petro-Canada's commercial paper program.

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 2004.

On May 11, 2005, Petro-Canada completed a $600 million US offering of 5.95% 30-year senior notes. This offering represents the balance available under the base shelf prospectus filed by Petro-Canada and its wholly owned subsidiary, PC Financial Partnership, on November 3, 2004. Net proceeds of the offering were used to repay existing short-term borrowing, with the balance used for working capital purposes.

Petro-Canada's cash and cash equivalents were $283 million as at June 30, 2005, compared with $170 million as at December 31, 2004.

Excluding cash and cash equivalents, short-term notes payable and the current portion of long-term debt, the operating working capital deficiency was $461 million at the end of the second quarter, compared with an operating working capital deficiency of $777 million as at December 31, 2004. The working capital deficiency was lower primarily due to an increase in accounts receivable and lower income taxes payable, partially offset by an increase in accounts payable.

The Company has certain retail licensee agreements that qualify as variable interest entities as described in Note 15 to the June 30, 2005 Consolidated Financial Statements. These entities are not consolidated as Petro-Canada is not the primary beneficiary and the Company's maximum exposure to losses from these arrangements would not be material.

Commitments and contingent liabilities are disclosed in Note 25 to the 2004 annual Consolidated Financial Statements. There has been no material change in these amounts as at June 30, 2005.

Contractual obligations are summarized in the Company's 2004 annual MD&A. During the second quarter of 2005, total contractual obligations increased by approximately $1.7 billion from March 31, 2005. The increase was mainly due to the $600 million US debt offering in May, including related interest, and the acquisition obligation for the Fort Hills oil sands mining project. These were partially offset by a reduction in debt obligations as a result of repaying short-term notes, payable with the proceeds from the debt offering.

2005 Capital Expenditure Program

In the second quarter of 2005, Petro-Canada's capital and exploration expenditures were $869 million(1), up from $624 million(2) in the same quarter of last year. For the six months ended June 30, 2005, Petro-Canada's capital and exploration expenditures were $1,794 million(1), compared with $1,116 million(2) for the same period in 2004. Capital and exploration expenditures include deferred charges and other assets. Capital expenditures in 2005 are expected to be $3,615 million, up from the December 16, 2004 outlook of $3,235 million. Increased capital expenditures are primarily focused on new growth opportunities. In the Downstream, increased expenditures include the acquisition of an interest in a petrochemical facility in Montreal and the expansion of the lubricants plant. In the upstream, additional expenditures reflect the acquisition of interests in the Fort Hills and Dover oil sands leases, additional exploration in International and accelerated progress on the White Rose project.

(1) Excludes the initial purchase obligation ($269 million on a discounted basis) in connection with the Company's acquisition of a 60% interest in the Fort Hills oil sands project. This purchase obligation will be reduced over time by Petro-Canada funding 75% of its partner's share of the next $1 billion of development capital. Petro-Canada's 2005 estimated expenditures incremental to the initial acquisition cost are included in the July 26, 2005 outlook.

(2) Excludes $1,218 million for the Buzzard acquisition.

(millions of dollars)	**2005 Outlook** As at July 26, 2005	**2005 Outlook** As at December 16, 2004
Upstream		
North American Natural Gas	$ 760	$ 760
East Coast Oil	355	315
Oil Sands (see footnote 1 above)	495	400
International	895	825
	2,505	2,300
Downstream		
Refining	915	780
Marketing	115	105
Lubricants	50	35
	1,080	920
Corporate	30	15
Total	$ 3,615	$ 3,235

RISK

Derivative Contracts

As part of its acquisition of an interest in the Buzzard field in the U.K. sector of the North Sea, Petro-Canada entered into a series of derivative contracts related to the future sale of Brent crude oil. Consistent with the rise in oil prices, mark-to-market unrealized losses associated with these Buzzard contracts have increased to $171 million after-tax in the second quarter of 2005, compared to $57 million in the second quarter of 2004. As the Buzzard development is not sufficiently advanced to qualify for hedge accounting, unrealized gains or losses are reported every quarter.

As at June 30, 2005, there was no material change in the Company's risks or risk management activities since December 31, 2004. Petro-Canada's risk management activities are conducted according to policies and guidelines established by the Board of Directors. Readers should refer to Petro-Canada's 2004 Annual Information Form and the risk management section of the 2004 annual MD&A.

SHAREHOLDER INFORMATION

As at June 30, 2005, Petro-Canada's common shares outstanding totaled 259.2 million and averaged 259.7 million in the second quarter. This compares with average shares outstanding of 266.2 million for the quarter ended June 30, 2004.

Petro-Canada will hold a conference call to discuss these results with investors on Wednesday, July 27, 2005 at 9 a.m. Eastern Time. To participate, please call 1-800-387-6216 or 416-405-9328 at 8:55 a.m. Media are invited to listen to the call by dialing 1-877-211-7911 and are invited to ask questions at the end of the call. Those who are unable to listen to the call live may listen to a recording of it approximately one hour after its completion by calling 1-800-408-3053 or 416-695-5800 (passcode number 3155794). A live audio broadcast of the conference call will be available on Petro-Canada's website at http://www.petro-canada.ca/eng/investor/9259.htm on July 27 at 9 a.m. Eastern Time. Approximately one hour after the call, a recording of the call will be available on the website.

Legal Notice – Forward-Looking Information

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

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

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

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

SELECTED OPERATING DATA
June 30, 2005

	Three months ended June 30, 2005	Three months ended June 30, 2004	Six months ended June 30, 2005	Six months ended June 30, 2004
Before Royalties				
Crude oil and natural gas liquids production, net (Mb/d)				
East Coast Oil	77.8	85.4	77.8	86.5
Oil Sands	48.9	40.7	43.7	44.0
North American Natural Gas (1)	14.5	13.7	15.3	14.4
Northwest Europe	26.3	43.7	30.3	45.3
North Africa/Near East	116.8	127.1	116.9	131.0
	284.3	310.6	284.0	321.2
Natural gas production, net, excluding injectants (MMcf/d)				
North American Natural Gas (1)	654	691	678	684
Northwest Europe	61	85	69	94
North Africa/Near East	26	21	27	21
Northern Latin America	74	71	75	69
	815	868	849	868
Total production(2) (Mboe/d), net before royalties	420	455	426	466
After Royalties				
Crude oil and natural gas liquids production, net (Mb/d)				
East Coast Oil	73.6	82.4	74.0	83.8
Oil Sands	48.4	40.3	43.3	43.6
North American Natural Gas (1)	10.9	10.1	11.5	10.6
Northwest Europe	25.2	43.7	29.7	45.3
North Africa/Near East	61.7	66.6	62.2	68.6
	219.8	243.1	220.7	251.9
Natural gas production, net, excluding injectants (MMcf/d)				
North American Natural Gas (1)	503	531	519	520
Northwest Europe	61	85	69	94
North Africa/Near East	4	6	5	5
Northern Latin America	49	40	62	54
	617	662	655	673
Total production (2) (Mboe/d), net after royalties	323	353	330	364
Petroleum product sales (thousands of cubic metres - m^3/d)				
Gasolines	25.2	25.1	24.2	24.5
Distillates	17.8	19.5	19.5	20.8
Other including petrochemicals	8.6	12.6	8.7	11.5
	51.6	57.2	52.4	56.8
Crude oil processed by Petro-Canada (thousands of m^3/d)	35.9	45.8	41.8	48.4
Average refinery utilization (%) (3)	87	92	94	97
Downstream earnings from operations after-tax (cents/litre) (4)	1.7	2.0	2.0	2.0

(1) North American Natural Gas includes Western Canada and U.S. Rockies.
(2) Natural gas converted at 6 Mcf of gas to one bbl of oil.
(3) Includes Oakville capacity pro-rated to reflect partial operation of Oakville refinery prior to permanent closure, effective April 11, 2005.
(4) Before additional depreciation and other charges related to the closure of the Oakville refinery.

AVERAGE PRICE REALIZED
June 30, 2005

	Three months ended June 30, 2005	Three months ended June 30, 2004	Six months ended June 30, 2005	Six months ended June 30, 2004
Crude oil and natural gas liquids ($/bbl)				
East Coast Oil	61.41	47.51	58.26	45.09
Oil Sands	44.35	41.10	41.18	38.31
North American Natural Gas [(1)]	56.83	44.98	54.87	42.26
Northwest Europe	66.38	48.90	61.08	46.19
North Africa/Near East	64.22	46.94	59.67	43.76
Total crude oil and natural gas liquids	59.85	46.52	56.33	43.65
Natural gas ($/Mcf)				
North American Natural Gas [(1)]	7.29	6.91	6.95	6.69
Northwest Europe	6.71	5.29	7.13	5.48
North Africa/Near East	7.01	5.02	5.87	4.66
Northern Latin America	5.05	4.99	5.07	4.86
Total natural gas	7.03	6.55	6.77	6.36

SHARE INFORMATION
June 30, 2005

	Three months ended June 30, 2005	Three months ended June 30, 2004	Six months ended June 30, 2005	Six months ended June 30, 2004
Weighted-average shares outstanding (millions)	259.7	266.2	259.9	266.1
Weighted-average diluted shares outstanding (millions)	263.0	269.7	263.2	269.6
Net earnings/share – Basic	$ 1.33	$ 1.48	$ 1.78	$ 3.41
– Diluted	$ 1.31	$ 1.46	$ 1.76	$ 3.36
Cash flow/share	$ 3.60	$ 3.22	$ 6.88	$ 6.59
Dividends/share	$ 0.15	$ 0.15	$ 0.30	$ 0.30
Share price [(2)] – High	$ 82.37	$ 64.67	$ 82.37	$ 69.69
Low	$ 67.30	$ 56.49	$ 59.01	$ 55.46
Close at June 30	$ 79.75	$ 57.65	$ 79.75	$ 57.65
Shares traded [(3)] (millions)	72.9	60.0	154.3	139.1

(1) North American Natural Gas includes Western Canada and U.S. Rockies.
(2) Share prices are for trading on the Toronto Stock Exchange (TSX).
(3) Total shares traded on the TSX and New York Stock Exchanges.

SELECTED FINANCIAL DATA
June 30, 2005
(unaudited, millions of Canadian dollars)

	Three months ended June 30, 2005	Three months ended June 30, 2004	Six months ended June 30, 2005	Six months ended June 30, 2004
Earnings				
Upstream				
North American Natural Gas	$ 117	$ 133	$ 220	$ 252
East Coast Oil	208	182	377	368
Oil Sands	34	25	15	59
International	116	72	229	195
Downstream	80	92	193	179
Shared Services	(56)	(33)	(100)	(65)
Earnings from operations	$ 499	$ 471	$ 934	$ 988
Foreign currency translation	8	(21)	4	(34)
Unrealized loss on Buzzard derivative contracts	(171)	(57)	(484)	(57)
Gain on asset sales	9	-	9	9
Net earnings	$ 345	$ 393	$ 463	$ 906
Cash flow				
Cash flow from operating activities	$ 1,011	$ 1,347	$ 1,574	$ 2,233
Increase (decrease) in non-cash working capital related to operating activities and other	(77)	(491)	214	(480)
Cash flow	$ 934	$ 856	$ 1,788	$ 1,753
Average capital employed				
Upstream			$ 8,495	$ 7,238
Downstream			2,993	2,590
Shared Services			95	276
Total Company			$ 11,583	$ 10,104
Return on capital employed [(1)] (%)				
Upstream			12.2	18.7
Downstream			11.2	6.6
Total Company			12.1	14.8
Operating return on capital employed [(1)] (%)				
Upstream			19.7	19.3
Downstream			10.8	7.2
Total Company			16.6	15.2
Return on equity (%)			15.3	18.1
Debt			$ 3,089	$ 2,290
Cash and cash equivalents			$ 283	$ 521
Debt to cash flow [(1)] (times)			0.8	0.7
Debt to debt plus equity (%)			26.1	21.4

(1) 12-month rolling average.

CONSOLIDATED STATEMENT OF EARNINGS *(unaudited)*
For the period ended June 30, 2005
(millions of Canadian dollars, except per share amounts)

	Three months ended June 30, 2005	Three months ended June 30, 2004	Six months ended June 30, 2005	Six months ended June 30, 2004
Revenue				
Operating	$ 4,286	$ 3,653	$ 8,166	$ 7,092
Investment and other income (Note 4)	(226)	(88)	(724)	(54)
	4,060	3,565	7,442	7,038
Expenses				
Crude oil and product purchases	2,096	1,666	3,948	3,139
Operating, marketing and general (Note 5)	758	669	1,454	1,324
Exploration	58	65	140	110
Depreciation, depletion and amortization (Note 5)	349	343	697	698
Unrealized (gain) loss on translation of foreign currency denominated long-term debt	(10)	26	(5)	42
Interest	39	38	73	75
	3,290	2,807	6,307	5,388
Earnings before income taxes	770	758	1,135	1,650
Provision for income taxes				
Current	461	424	892	819
Future (Note 6)	(36)	(59)	(220)	(75)
	425	365	672	744
Net earnings	$ 345	$ 393	$ 463	$ 906
Earnings per share (Note 8)				
Basic (dollars)	$ 1.33	$ 1.48	$ 1.78	$ 3.41
Diluted (dollars)	$ 1.31	$ 1.46	$ 1.76	$ 3.36

CONSOLIDATED STATEMENT OF RETAINED EARNINGS *(unaudited)*
For the period ended June 30, 2005
(millions of Canadian dollars)

	Three months ended June 30, 2005	Three months ended June 30, 2004	Six months ended June 30, 2005	Six months ended June 30, 2004
Retained earnings at beginning of period	$ 5,487	$ 4,283	$ 5,408	$ 3,810
Net earnings	345	393	463	906
Dividends on common shares	(39)	(40)	(78)	(80)
Retained earnings at end of period	$ 5,793	$ 4,636	$ 5,793	$ 4,636

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENT OF CASH FLOWS *(unaudited)*
For the period ended June 30, 2005
(millions of Canadian dollars)

	Three months ended June 30, 2005	Three months ended June 30, 2004	Six months ended June 30, 2005	Six months ended June 30, 2004
		(restated)		*(restated)*
Operating activities				
Net earnings	$ 345	$ 393	$ 463	$ 906
Items not affecting cash flow from operating activities:				
Depreciation, depletion and amortization	349	343	697	698
Future income taxes	(36)	(59)	(220)	(75)
Accretion of asset retirement obligations	13	12	29	24
Unrealized (gain) loss on translation of foreign currency denominated long-term debt	(10)	26	(5)	42
Gain on disposals of assets (Note 4)	(14)	-	(14)	(10)
Unrealized loss associated with the Buzzard derivative contracts (Note 14)	272	93	764	93
Other	(8)	12	1	18
Exploration expenses (Note 3)	23	36	73	57
Proceeds from sale of accounts receivable (Note 9)	-	399	80	399
(Increase) decrease in non-cash working capital related to operating activities	77	92	(294)	81
Cash flow from operating activities	1,011	1,347	1,574	2,233
Investing activities				
Expenditures on property, plant and equipment and exploration (Notes 3 and 7)	(1,076)	(1,805)	(1,955)	(2,267)
Proceeds from sale of assets	20	2	21	32
Increase in deferred charges and other assets	(27)	(8)	(41)	(14)
(Increase) decrease in non-cash working capital and other related to investing activities	191	10	210	(4)
	(892)	(1,801)	(1,765)	(2,253)
Financing activities				
Increase (decrease) in short-term notes payable	(588)	286	(279)	286
Proceeds from issue of long-term debt (Note 10)	762	-	762	-
Repayment of long-term debt	(2)	(295)	(3)	(296)
Proceeds from issue of common shares (Note 11)	18	9	45	24
Purchase of common shares (Note 11)	(75)	(10)	(142)	(10)
Dividends on common shares	(39)	(40)	(78)	(80)
(Increase) decrease in non-cash working capital related to financing activities	(1)	9	(1)	(18)
	75	(41)	304	(94)
Increase (decrease) in cash and cash equivalents	194	(495)	113	(114)
Cash and cash equivalents at beginning of period	89	1,016	170	635
Cash and cash equivalents at end of period	$ 283	$ 521	$ 283	$ 521

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED BALANCE SHEET *(unaudited)*
As at June 30, 2005
(millions of Canadian dollars)

	June 30, 2005	December 31, 2004
Assets		
Current assets		
Cash and cash equivalents	$ 283	$ 170
Accounts receivable (Note 9)	1,558	1,254
Inventories	578	549
Prepaid expenses	45	13
	2,464	1,986
Property, plant and equipment, net	15,801	14,783
Goodwill	915	986
Deferred charges and other assets	396	345
	$ 19,576	$ 18,100
Liabilities and shareholders' equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 2,398	$ 2,223
Income taxes payable	244	370
Short-term notes payable	24	299
Current portion of long-term debt	7	6
	2,673	2,898
Long-term debt (Note 10)	3,058	2,275
Other liabilities	1,702	646
Asset retirement obligations	842	834
Future income taxes	2,538	2,708
Shareholders' equity		
Common shares (Note 11)	1,353	1,314
Contributed surplus	1,611	1,743
Retained earnings	5,793	5,408
Foreign currency translation adjustment	6	274
	8,763	8,739
	$ 19,576	$ 18,100

See accompanying Notes to Consolidated Financial Statements

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS *(unaudited)*
(millions of Canadian dollars)

1 SEGMENTED INFORMATION

Three months ended June 30,

	Upstream													
	North American Natural Gas		East Coast Oil		Oil Sands		International		Downstream		Shared Services		Consolidated	
	2005	2004	2005	2004	2005	2004	2005	2004	2005	2004	2005	2004	2005	2004
Revenue														
Sales to customers	$ 452	447	$ 359	261	168	85	662	523	$2,645	2,337	-	-	4,286	$ 3,653
Investment and other income	1	-	-	-	1	-	(251)	(89)	35	(4)	(12)	5	(226)	(88)
Inter-segment sales	76	52	58	105	171	130	-	-	3	2	-	-		
Segmented revenue	529	499	417	366	340	215	411	434	2,683	2,335	(12)	5	4,060	3,565
Expenses														
Crude oil and product purchases	106	93	-	-	133	64	-	-	1,861	1,511	(4)	(2)	2,096	1,666
Inter-segment transactions	-	-	3	2	17	12	-	-	288	275	-	-		
Operating, marketing and general	109	93	36	26	104	90	125	110	345	333	39	17	758	669
Exploration	22	23	-	2	3	-	33	40	-	-	-	-	58	65
Depreciation, depletion and amortization	90	75	73	70	30	12	103	116	52	69	1	1	349	343
Unrealized (gain) loss on translation of foreign currency denominated long-term debt	-	-	-	-	-	-	-	-	-	-	(10)	26	(10)	26
Interest	-	-	-	-	-	-	-	-	-	-	39	38	39	38
	327	284	112	100	287	178	261	266	2,546	2,188	65	80	3,290	2,807
Earnings (loss) before income taxes	202	215	305	266	53	37	150	168	137	147	(77)	(75)	770	758
Provision for income taxes														
Current	69	94	87	87	7	(13)	257	198	71	77	(30)	(19)	461	424
Future	16	(12)	10	(3)	12	25	(52)	(45)	(23)	(22)	1	(2)	(36)	(59)
	85	82	97	84	19	12	205	153	48	55	(29)	(21)	425	365
Net earnings (loss)	$ 117	133	$ 208	182	34	25	(55)	$ 15	89	92	$(48)	$ (54)	$ 345	393
Expenditures on property, plant and equipment and exploration	$ 131	173	$ 68	70	396	79	253	1,286	224	195	4	2	1,076 [1]	$ 1,805 [1]
Cash flow from operating activities	$ 255	251	$ 215	214	73	74	243	308	262	418	$(37)	$ 82	1,011	1,347

[1] Expenditures include capitalized interest in the amount of $9 million for the three months ended June 30, 2005 ($3 million for the three months ended June 30, 2004).

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS *(unaudited)*

(millions of Canadian dollars)

1 SEGMENTED INFORMATION

Six months ended June 30,

	Upstream													
	North American Natural Gas		East Coast Oil		Oil Sands		International		Downstream		Shared Services		Consolidated	
	2005	2004	2005	2004	2005	2004	2005	2004	2005	2004	2005	2004	2005	2004
Revenue														
Sales to customers	$ 883	$ 865	$ 596	$ 504	$ 297	$ 180	$ 1,254	$ 1,084	$ 5,136	$ 4,459	$ -	$ -	$ 8,166	$ 7,092
Investment and other income	1	1	-	-	-	-	(738)	(71)	28	5	(15)	11	(724)	(54)
Inter-segment sales	149	98	176	241	281	255	-	-	7	5	-	-		
Segmented revenue	1,033	964	772	745	578	435	516	1,013	5,171	4,469	(15)	11	7,442	7,038
Expenses														
Crude oil and product purchases	201	186	-	-	242	125	-	-	3,505	2,825	-	3	3,948	3,139
Inter-segment transactions	4	3	3	2	32	22	-	-	574	572	-	-		
Operating, marketing and general	201	178	80	61	199	172	236	230	672	653	66	30	1,454	1,324
Exploration	64	48	-	2	31	9	45	51	-	-	-	-	140	110
Depreciation, depletion and amortization	184	149	136	142	50	24	221	246	105	136	1	1	697	698
Unrealized (gain) loss on translation of foreign currency denominated long-term debt	-	-	-	-	-	-	-	-	-	-	(5)	42	(5)	42
Interest	-	-	-	-	-	-	-	-	-	-	73	75	73	75
	654	564	219	207	554	352	502	527	4,856	4,186	135	151	6,307	5,388
Earnings (loss) before income taxes	379	400	553	538	24	83	14	486	315	283	(150)	(140)	1,135	1,650
Provision for income taxes														
Current	148	182	172	163	(22)	(27)	476	398	171	142	(53)	(39)	892	819
Future	11	(34)	4	7	31	51	(207)	(58)	(58)	(39)	(1)	(2)	(220)	(75)
	159	148	176	170	9	24	269	340	113	103	(54)	(41)	672	744
Net earnings (loss)	$ 220	$ 252	$ 377	$ 368	$ 15	$ 59	$ (255)	$ 146	$ 202	$ 180	$ (96)	$ (99)	$ 463	$ 906
Expenditures on property, plant and equipment and exploration	$ 380	$ 305	$ 127	$ 121	$ 546	$ 165	$ 420	$ 1,358	$ 478	$ 316	$ 4	$ 2	$ 1,955 [1]	$ 2,267 [1]
Cash flow from operating activities	$ 490	$ 450	$ 442	$ 490	$ 110	$ 150	$ 423	$ 585	$ 273	$ 527	$ (164)	$ 31	$ 1,574	$ 2,233

[1] Expenditures include capitalized interest in the amount of $17 million for the six months ended June 30, 2005 ($5 million for the six months ended June 30, 2004).

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS *(unaudited)*
(millions of Canadian dollars, unless otherwise stated)

2. BASIS OF PRESENTATION

The note disclosure requirements for annual Consolidated Financial Statements provide additional disclosure to that required for interim Consolidated Financial Statements. Accordingly, these interim Consolidated Financial Statements should be read in conjunction with the Consolidated Financial Statements included in the Company's 2004 Annual Report. The interim Consolidated Financial Statements are presented in accordance with Canadian generally accepted accounting principles and follow the accounting policies summarized in the notes to the annual Consolidated Financial Statements except for the change described in Note 3.

3. CHANGES IN ACCOUNTING POLICIES

Statement of Cash Flows

Effective January 1, 2005, the Company changed the presentation of cash flow in the Consolidated Statement of Cash Flows pursuant to recent interpretations from the United States Securities and Exchange Commission. Previously, all exploration expenses were classified as investing activities. With the change, general and administrative and geological and geophysical exploration expenses are treated as a reduction of cash flow from operating activities. All prior periods have been restated to reflect this change. The change results in a decrease in cash flow from operating activities and an increase in cash flow from investing activities by $35 million for the three months ended June 30, 2005 ($29 million for the three months ended June 30, 2004) and $67 million for the six months ended June 30, 2005 ($53 million for the six months ended June 30, 2004).

4. INVESTMENT AND OTHER INCOME

Investment and other income includes net losses on derivative contracts (see Note 14) of $254 million and $759 million for the three and six months ended June 30, 2005, respectively ($95 million and $90 million for the three and six months ended June 30, 2004) and net gains on disposal of assets of $14 million for the three and six months ended June 30, 2005, respectively ($ nil and $10 million for the three and six months ended June 30, 2004).

5. ASSET WRITE-DOWNS

Following a review of its Eastern Canada refining and supply operations, Petro-Canada announced in September 2003 it would cease the Oakville refining operations and expand the existing terminalling facilities. The total charge to earnings related to the shutdown, which occurred in April 2005, was approximately $200 million after-tax. The following expenses have been recorded in the Downstream segment:

	Three months ended June 30,				Six months ended June 30,			
	2005		2004		2005		2004	
	Pre-Tax	After-Tax	Pre-Tax	After-Tax	Pre-Tax	After-Tax	Pre-Tax	After-Tax
Operating, marketing and general expense (de-commissioning and employee related costs)	$ -	$ -	$ 1	$ -	$ 1	$ 1	$ 2	$ 1
Depreciation and amortization expenses (asset write-downs and increased depreciation)	1	-	20	13	1	-	40	25
	$ 1	$ -	$ 21	$ 13	$ 2	$ 1	$ 42	$ 26

6. INCOME TAXES

The provision for future income taxes for the six months ended June 30, 2004 was reduced by $13 million due to the substantively enacted reduction in 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 - $7 million, East Coast Oil - $3 million, Oil Sands - $2 million, Downstream - $2 million and Shared Services - $(1) million.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS *(unaudited)*

7. FORT HILLS OIL SANDS MINING PROJECT

In June 2005, the Company acquired a 60% interest in the Fort Hills oil sands mining project which was previously wholly owned by UTS Energy Corporation (UTS). To pay for the investment, Petro-Canada will fund 75% of UTS' share of the next $1 billion of development capital, or $300 million.

Expenditures on property, plant and equipment and exploration in the Consolidated Statement of Cash Flows include the discounted value of the acquisition cost amounting to $269 million.

8. EARNINGS PER SHARE

The following table provides the common shares used in calculating net earnings per common share:

	Three months ended June 30,		Six months ended June 30,	
(millions)	2005	2004	2005	2004
Weighted-average number of common shares outstanding - basic	259.7	266.2	259.9	266.1
Effect of dilutive stock options	3.3	3.5	3.3	3.5
Weighted-average number of common shares outstanding - diluted	263.0	269.7	263.2	269.6

9. SECURITIZATION PROGRAM

During 2004, the Company entered into a securitization program, expiring in 2009, to sell an undivided interest of eligible accounts receivable to a third party, on a revolving and fully serviced basis.

In March 2005, Petro-Canada increased the limit to sell eligible accounts receivable under the program from $400 million to $500 million. During the six months ended June 30, 2005, the Company sold an additional $80 million of outstanding receivables for net proceeds of $80 million.

As at June 30, 2005, $480 million of outstanding accounts receivable had been sold under the program.

10. LONG-TERM DEBT

	Maturity	June 30, 2005
Debentures and notes		
5.95% unsecured senior notes [1] ($600 million US)	2035	$ 735
5.35% unsecured senior notes ($300 million US)	2033	368
7.00% unsecured debentures ($250 million US)	2028	306
7.875% unsecured debentures ($275 million US)	2026	337
9.25% unsecured debentures ($300 million US)	2021	368
5.00% unsecured senior notes ($400 million US)	2014	490
4.00% unsecured senior notes ($300 million US)	2013	368
Capital leases	2007-2017	83
Retail licensee trust loans	2012-2014	10
		3,065
Current portion		(7)
		$ 3,058

[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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS *(unaudited)*

11. SHAREHOLDERS' EQUITY

Changes in common shares:

	Number	Amount
Balance at January 1, 2005	259,964,011	$ 1,314
Issued upon exercise of stock options	1,229,052	45
Purchased	(1,966,700)	(10)
Stock-based compensation	-	4
Balance at June 30, 2005	259,226,363	$ 1,353

In June 2005, the Company renewed its normal course issuer bid to repurchase up to 13 million of its common shares during the period from June 22, 2005 to June 21, 2006, subject to certain conditions. The Company purchased 1,021,800 shares at a cost of $75 million and 1,966,700 shares at a cost of $142 million during the three and six months ended June 30, 2005, respectively (166,000 shares at a cost of $10 million during the three and six months ended June 30, 2004). The excess of the purchase price over the carrying amount of the shares purchased, which totaled $70 million and $132 million for the three and six months ended June 30, 2005, respectively, was recorded as a reduction of contributed surplus.

12. STOCK-BASED COMPENSATION

Changes in the number of outstanding stock options and performance share units (PSUs) were as follows:

	Stock Options		PSUs
	Number	Weighted-Average Exercise Price *(dollars)*	Number
Balance at January 1, 2005	9,037,349	$ 41.82	282,930
Granted	2,002,400	68.56	319,171
Exercised	(1,229,052)	36.29	-
Cancelled	(93,224)	57.21	(14,416)
Balance at June 30, 2005	9,717,473	$ 58.16	587,685

During the three and six months ended June 30, 2005, total stock-related compensation expense recorded in the Consolidated Statement of Earnings was $19 million and $37 million, respectively ($2 million and $5 million for the three and six months ended June 30, 2004).

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS *(unaudited)*

Compensation expense has not been recorded for stock options issued prior to 2003. The following table presents the pro forma net earnings and the pro forma earnings per share computed assuming the fair value based accounting method had been used to account for the compensation cost of stock options granted in 2002.

Three months ended June 30,	Net earnings 2005	Net earnings 2004	Earnings per share (dollars) 2005 Basic	2005 Diluted	2004 Basic	2004 Diluted
Net earnings as reported	$ 345	$ 393	$ 1.33	$ 1.31	$ 1.48	$ 1.46
Pro forma adjustment	2	3	0.01	0.01	0.02	0.01
Pro forma net earnings	$ 343	$ 390	$ 1.32	$ 1.30	$ 1.46	$ 1.45

Six months ended June 30,	Net earnings 2005	Net earnings 2004	Earnings per share (dollars) 2005 Basic	2005 Diluted	2004 Basic	2004 Diluted
Net earnings as reported	$ 463	$ 906	$ 1.78	$ 1.76	$ 3.41	$ 3.36
Pro forma adjustment	4	5	0.01	0.02	0.02	0.02
Pro forma net earnings	$ 459	$ 901	$ 1.77	$ 1.74	$ 3.39	$ 3.34

13. 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 expenses associated with these plans are as follows:

	Three months ended June 30, 2005	Three months ended June 30, 2004	Six months ended June 30, 2005	Six months ended June 30, 2004
Pension Plans:				
Defined benefit plans				
Employer current service cost	$ 8	$ 7	$ 16	$ 13
Interest cost	21	20	42	40
Expected return on plan assets	(21)	(19)	(43)	(38)
Amortization of transitional asset	(1)	(1)	(2)	(2)
Amortization of net actuarial losses	8	7	17	15
	15	14	30	28
Defined contribution plan	3	3	7	6
	$ 18	$ 17	$ 37	$ 34
Other post-retirement plans:				
Employer current service cost	$ 1	$ 1	$ 2	$ 2
Interest cost	3	3	6	6
Amortization of transitional obligation	-	1	1	2
	$ 4	$ 5	$ 9	$ 10

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS *(unaudited)*

The Company expects to contribute $95 million to its defined benefit pension plans in 2005. As at June 30, 2005, $48 million in contributions have been made.

14. FINANCIAL INSTRUMENTS AND DERIVATIVES

Investment and other income includes unrealized losses for the outstanding derivatives contracts associated with the 2004 acquisition of an interest in the Buzzard field in the U.K. sector of the North Sea. For the three months and six months ended June 30, 2005, the unrealized losses relating to these contracts amounted to $272 million and $764 million, respectively ($93 million for the three and six months ended June 30, 2004).

Unrealized losses on all derivative contracts have decreased investment and other income by $263 million and $757 million for the three and six months ended June 30, 2005. As at June 30, 2005 accounts receivable and other liabilities have been increased by $11 million and $1,097 million, respectively as result of unrealized mark-to-market amounts on derivative contracts.

15. 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 variable interest entity's activities, or is entitled to receive a majority of the variable interest entity's residual returns, or both. The Company determined that certain retail licensee 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 these 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.

16. SUBSEQUENT EVENTS

On July 26, 2005, the Board of Directors declared a stock-split effected in the form of a dividend. Common shareholders of record at the close of business on September 3, 2005 will receive one additional common share for each common share they hold. The stock dividend is payable on September 14, 2005.

Commencing with the fourth quarter dividend paid on October 1, 2005, the Company will increase the quarterly dividend to $0.20 per share on a pre-split basis.