2009 Quarterly Report

PETRO-CANADA

April 28, 2009 (publié également en français)

For the 3 months ended March 31, 2009

MANAGEMENT'S DISCUSSION AND ANALYSIS

The Management's Discussion and Analysis (MD&A), dated April 28, 2009, is set out in pages 1 to 22 and should be read in conjunction with the unaudited Consolidated Financial Statements of the Company for the three months ended March 31, 2009; the MD&A for the year ended December 31, 2008, the audited Consolidated Financial Statements for the year ended December 31, 2008, and the Company's 2008 Annual Information Form (AIF), dated March 18, 2009. Amounts are in Canadian (Cdn) dollars unless otherwise specified.

LEGAL NOTICE – FORWARD-LOOKING INFORMATION

This quarterly 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 terms that suggest future outcomes or references to outlooks. Listed below are examples of references to forward-looking information:

- business strategies and goals
- future investment decisions
- outlook (including operational updates and strategic milestones)
- future capital, exploration and other expenditures
- future cash flows
- future resource purchases and sales
- anticipated construction and repair activities
- anticipated turnarounds at refineries and other facilities
- anticipated refining margins
- future oil and natural gas production levels and the sources of their growth
- project development, and expansion schedules and results
- future exploration activities and results, and dates by which certain areas may be developed or come on-stream
- anticipated retail throughputs
- anticipated pre-production and operating costs
- reserves and resources estimates
- future 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)
- the impact and cost of compliance with existing and potential environmental matters
- future regulatory approvals
- expected rates of return

Such forward-looking information is based on a number of assumptions and analysis made by the Company. These assumptions and analysis are described in greater detail throughout this quarterly report and include, without limitation, assumptions with respect to future commodity prices, the state of the economy, required capital expenditures, levels of cash flow, regulatory requirements, industry capacity, the results of exploration and development drilling and the ability of suppliers to meet commitments.

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

- the possibility of corporate amalgamations and reorganizations
- changes in 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 associated with domestic and international oil and natural gas operations
- changes in general economic, market and business conditions
- competitive action by other companies
- fluctuations in oil and natural gas prices
- changes in 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
- nature and scope of actions by stakeholders and/or the general public

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).

Readers are cautioned that this list of important factors affecting forward-looking information is not exhaustive. Furthermore, the forward-looking information in this quarterly report is made as of April 28, 2009 and, except as required by applicable law, will not be publicly updated or revised. This cautionary statement expressly qualifies the forward-looking information in this quarterly 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 Petro-Canada's reserves staff and management as independent of the Company. Petro-Canada has obtained an exemption from certain Canadian reserves disclosure requirements that allows Petro-Canada to make disclosure in accordance with SEC standards where noted in this quarterly report. This exemption allows comparisons with U.S. and other international issuers.

As a result, Petro-Canada formally discloses its proved reserves data using U.S. requirements and practices, and these may differ from Canadian domestic standards and practices. The use of the terms such as "*probable*," "*possible*," "*resources*" and "*life-of-field production*" in this quarterly report does not meet the SEC guidelines for SEC filings. To disclose reserves in SEC filings, oil and gas companies must prove they are economically and legally producible under existing economic and operating conditions. Note that when the term barrels of oil equivalent (boe) is used in this quarterly 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. The table below describes the industry definitions that Petro-Canada currently uses:

Definitions Petro-Canada uses	**Reference**
Proved oil and natural gas reserves (includes both proved developed and proved undeveloped)	SEC reserves definition (Accounting Rules Regulation S-X 210.4-10, U.S. Financial Accounting Standards Board Statement No. 69) SEC Guide 7 for Oil Sands Mining
Unproved reserves, probable and possible reserves	Canadian Securities Administrators: Canadian Oil and Gas Evaluation Handbook (COGEH), Vol. 1 Section 5 prepared by the Society of Petroleum Evaluation Engineers (SPEE) and the Canadian Institute of Mining Metallurgy and Petroleum (CIM)
Contingent and Prospective Resources	Petroleum Resources Management System: Society of Petroleum Engineers, SPEE, World Petroleum Congress and American Association of Petroleum Geologist definitions (approved March 2007) Canadian Securities Administrators: COGEH Vol. 1 Section 5

Although the Society of Petroleum Engineers resource classification has categories of 1C, 2C and 3C for Contingent Resources, and low, best and high estimates for Prospective Resources, Petro-Canada will only refer to the unrisked 2C for Contingent Resources and the partially risked best estimate for Prospective Resources when referencing resources in this quarterly report. Estimates of resources in this quarterly report include Contingent Resources that have not been adjusted for risk based on the chance of development and partially risked Prospective Resources that have been risked for chance of discovery, but have not been risked for chance of development. Such estimates are not estimates of volumes that may be recovered and actual recovery is likely to be less and may be substantially less or zero. If a discovery is made, there is no certainty that it will be developed or, if it is developed, there is no certainty as to the timing of such development.

Canadian Oil Sands represents approximately 68% of Petro-Canada's total for Contingent and Prospective Resources. The balance of Petro-Canada's resources is spread out across the business, most notably in the North American frontier and International areas. Also, when Petro-Canada references resources for the Company, unrisked Contingent Resources are approximately 70% of the Company's total resources and partially risked Prospective Resources are approximately 30% of the Company's total resources.

Cautionary statement: In the case of discovered resources or a subcategory of discovered resources other than reserves, there is no certainty that it will be commercially viable to produce any portion of the resources. In the case of undiscovered resources or a subcategory of undiscovered resources, there is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

For movement of resources to reserves categories, all projects must have an economic depletion plan and may require:

- additional delineation drilling and/or new technology for unrisked Contingent Resources
- exploration success with respect to partially risked Prospective Resources
- project sanction and regulatory approvals

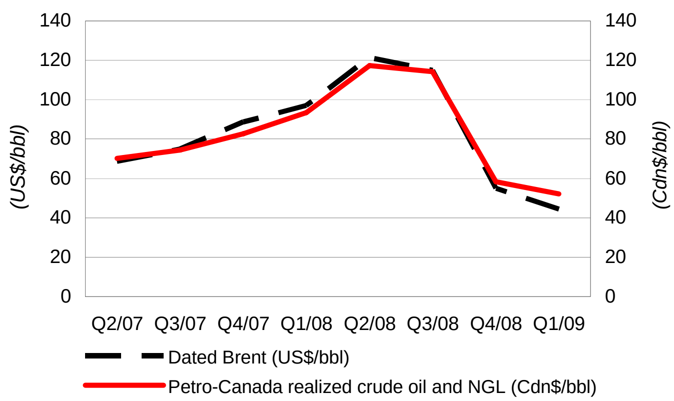
Reserves and resources information contained in this quarterly report is as at December 31, 2008.

BUSINESS ENVIRONMENT

Market prices shown below influence average prices realized for crude oil and natural gas liquids (NGL), natural gas and petroleum products in the tables on pages 20 and 21.

UPSTREAM

Crude Oil



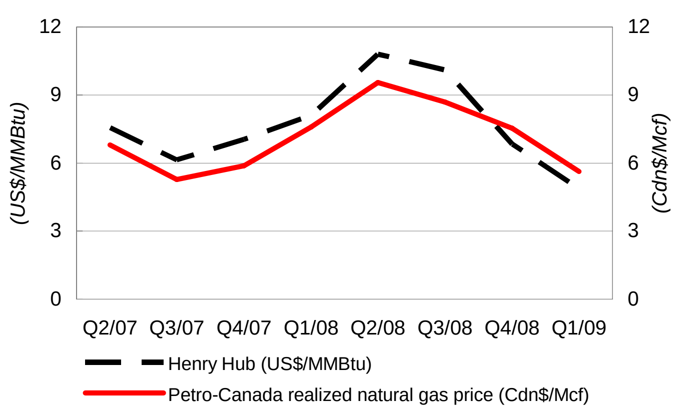
The price of Dated Brent averaged $44.40 US/bbl in the first quarter of 2009, down 54% compared with $96.90 US/bbl in the first quarter of 2008. Large scale reductions in global industrial activity and trade depressed crude oil demand in the first quarter of 2009.

Weaker energy prices drove down the value of the Canadian dollar in the first quarter of 2009, averaging $0.80 US, 20 cents lower than the $1.00 US average in the first quarter of 2008.

As a result, Petro-Canada's corporate-wide realized Canadian dollar prices for crude oil and NGL decreased 44%, from $93.38/bbl in the first quarter of 2008 to $52.08/bbl in the first quarter of 2009.

In the first quarter of 2009, the spread between Dated Brent and Mexican Maya narrowed to $5.89 US/bbl, compared with $15.77 US/bbl in the first quarter of 2008. In Canada, the spread between Edmonton Light and Western Canada Select (WCS) narrowed to $9.02/bbl in the first quarter of 2009, compared with $21.61/bbl in the first quarter of 2008.

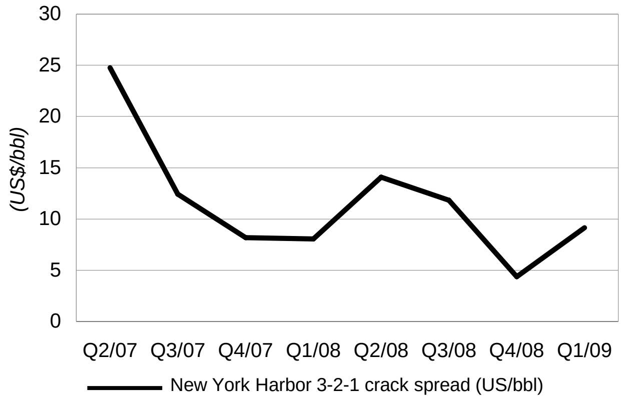
Natural Gas



North American natural gas prices at the Henry Hub were lower in the first quarter of 2009, compared with the first quarter of 2008, reflecting strong growth in U.S. domestic production and much weaker industrial demand. Downward price pressure was mitigated somewhat by higher heating demand. In the first quarter of 2009, NYMEX Henry Hub natural gas prices averaged $4.86 US/million British thermal units (MMBtu), down 40% from $8.09 US/MMBtu in the first quarter of 2008. Canadian natural gas prices were also lower despite some mitigation from the weaker currency. Natural gas prices at the AECO-C hub averaged $5.87/Mcf in the first quarter of 2009, down from $7.44/Mcf in the first quarter of 2008.

Petro-Canada's realized Canadian dollar prices for its North American Natural Gas business averaged $5.14/Mcf in the first quarter of 2009, down 32% from $7.51/Mcf in the first quarter of 2008.

DOWNSTREAM



New York Harbor 3-2-1 refinery crack spreads averaged $9.16 US/bbl in the first quarter of 2009, up 14% compared with an average of $8.06 US/bbl in the first quarter of 2008. Gasoline crack spreads strengthened as lower refinery throughputs helped reduce gasoline inventories. However, heating oil crack spreads were lower compared with the first quarter of 2008, as economic weakness reduced distillate demand due to lower industrial, mining and shipping activity.

The average market prices for the periods stated were:

	Three months ended March 31,	
	2009	2008
Dated Brent at Sullom Voe (*US$/bbl)*	**44.40**	96.90
West Texas Intermediate (WTI) at Cushing (*US$/bbl)*	**43.08**	97.90
Dated Brent/Maya FOB price differential *(US$/bbl)*	**5.89**	15.77
Edmonton Light (*Cdn$/bbl)*	**51.64**	98.08
Edmonton Light/WCS FOB price differential *(Cdn$/bbl)*	**9.02**	21.61
Natural gas at Henry Hub (*US$/MMBtu)*	**4.86**	8.09
Natural gas at AECO (*Cdn$/Mcf)*	**5.87**	7.44
New York Harbor 3-2-1 crack spread (*US$/bbl)*	**9.16**	8.06
Exchange rate (*US cents/Cdn$)*	**80.3**	99.6
Average realized prices		
Crude oil and NGL *($/barrel – $/bbl)*	**52.08**	93.38
Natural gas (*$/thousand cubic feet – $/Mcf)*	**5.62**	7.59

The following table shows the estimated after-tax effects that changes in certain factors would have had on Petro-Canada's 2008 net earnings had these changes occurred. Amounts are in Canadian dollars unless otherwise specified.

Factor [1, 2]	Change (+)	Annual net earnings impact *(millions of dollars)*	Annual net earnings impact *($/share)* [3]
Upstream			
Price received for crude oil and NGL [4]	$1.00/bbl	$ 54	$ 0.11
Price received for natural gas	$0.25/Mcf	30	0.06
Exchange rate: US$/Cdn$ refers to impact on upstream earnings[5]	$0.01	(60)	(0.12)
Crude oil and NGL production (*barrels/day – b/d*)	1,000 b/d	15	0.03
Natural gas production (*million cubic feet/day – MMcf/d*)	10 MMcf/d	11	0.02
Downstream			
New York Harbor 3-2-1 crack spread	$1.00 US/bbl	22	0.05
Chicago 3-2-1 crack spread	$1.00 US/bbl	20	0.04
Seattle 3-2-1 crack spread	$1.00 US/bbl	9	0.02
WTI/Dated Brent price differential	$1.00 US/bbl	25	0.05
Dated Brent/Maya FOB price differential	$1.00 US/bbl	5	0.01
WTI/Synthetic price differential	$1.00 US/bbl	14	0.03
Exchange rate: US$/Cdn$ refers to impact on Downstream cracking margins and crude price differentials [6]	$0.01	(11)	(0.02)
Natural gas fuel cost – AECO natural gas price	$1.00 Cdn/Mcf	(10)	(0.02)
Asphalt – % of Maya crude oil price	1%	2	–
Heavy fuel oil (HFO) – % of WTI crude oil price	1%	2	–
Corporate			
Exchange rate: US$/Cdn$ refers to impact of the revaluation of U.S. dollar-denominated long-term debt [7]	$0.01	$ 31	$ 0.06

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 as at December 31, 2008.
4 This sensitivity is based upon an equivalent change in the price of WTI and Dated Brent.
5 A strengthening Canadian dollar compared with the U.S. dollar has a negative effect on upstream net earnings.
6 A strengthening Canadian dollar compared with the U.S. dollar has a negative effect on downstream cracking margins and crude price differentials.
7 A strengthening Canadian dollar versus the U.S. dollar has a positive effect on corporate earnings with respect to the Company's U.S. dollar-denominated debt. The impact refers to gains or losses on $2.9 billion US of the Company's U.S. dollar-denominated long-term debt and interest costs on U.S. dollar-denominated debt. Gains or losses on $1.1 billion US of the Company's U.S. dollar-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 unit, are deferred and included as part of shareholders' equity.

BUSINESS STRATEGY

Petro-Canada's strategy is to create shareholder value by delivering long-term, profitable growth and improving the profitability of the base business. On March 23, 2009, the Company announced plans to merge with Suncor Energy Inc. (Suncor) to create the premier Canadian energy company.

Petro-Canada's capital program supports bringing on six major projects over the next several years to deliver long-term profitable growth. The Company anticipates upstream production will significantly increase when these major growth projects come on-stream. The Company plans to advance the extension of the White Rose field off the East Coast of Canada, the Syria Ebla gas project and the developments associated with the new Libya Exploration and Production Sharing Agreements (EPSAs), which have been sanctioned by the Company. The other three projects, MacKay River expansion, Fort Hills mining project and the Montreal coker, are not sanctioned and are on hold until commodity prices and financial markets stabilize and the proposed merger with Suncor is completed.

Petro-Canada continually works to strengthen its base business by improving the safety, reliability and efficiency of its operations and is focused on delivering upstream production in line with guidance.

Strategic Priorities	Quarterly Update
DELIVERING PROFITABLE GROWTH WITH A FOCUS ON OPERATED, LONG-LIFE ASSETS	• announced plans to merge with Suncor to create Canada's premier energy company • continued ramp up of the Edmonton refinery conversion project (RCP) • received regulatory approval and Order in Council for the Fort Hills Sturgeon Upgrader • reached agreement with the Government of Alberta on extending the Fort Hills project mine leases until 2019
DRIVING FOR FIRST QUARTILE OPERATION OF OUR ASSETS	• achieved 96% facility reliability at Terra Nova • maintained reliability at 99% for Western Canada natural gas production operations • operated MacKay River at 98% reliability • delivered a combined reliability index of 95 at all three Downstream production facilities • grew convenience store sales and same-store sales by 4%, compared with the first quarter of 2008
MAINTAINING FINANCIAL DISCIPLINE AND FLEXIBILITY	• ended the quarter with debt levels at 24.2% of total capital and a ratio of 1.1 times debt-to-cash flow from operating activities • reduced planned 2009 capital expenditures by $600 million to $3.4 billion • maintained adequate liquidity via quarter-end cash balance of $772 million and unutilized credit facility capacity of $4.8 billion
CONTINUING TO WORK AT BEING A RESPONSIBLE COMPANY	• experienced total recordable injury frequency (TRIF) of 0.76, slightly higher than a TRIF of 0.73 in 2008 • invested nearly $2 million in launching three new water partnerships created jointly with Canadian Parks and Wilderness Society, Centre for Affordable Water and Sanitation Technology and Alberta Ecotrust Foundation

STRATEGIC MILESTONES

Q2 2009

- continue appraisal drilling of the Hobby discovery in the United Kingdom Continental Shelf (UKCS)

Q3 2009

- plan to commence drilling offshore exploration wells in East Coast Canada, Norway and the UKCS, with the latter dependent on rig availability
- plan to commence Libya exploration drilling program

Q4 2009

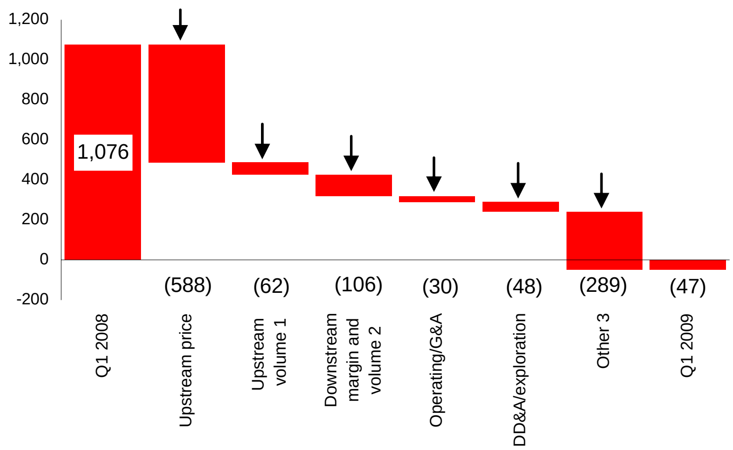
- plan to commence handover of Syria Ebla gas plant utilities systems to operations

ANALYSIS OF CONSOLIDATED EARNINGS

Earnings Variances

Q1/09 VERSUS Q1/08 FACTOR ANALYSIS

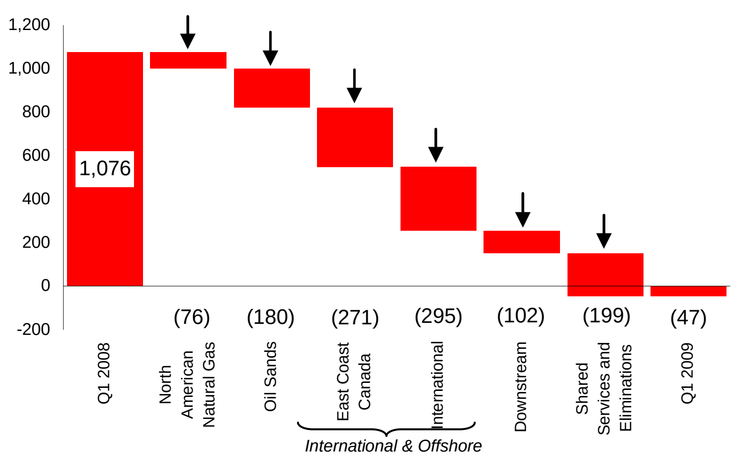
Net Earnings
(millions of Canadian dollars, after-tax)



The Company recorded a net loss in the first quarter of 2009 of $47 million ($(0.10)/share), compared with net earnings of $1,076 million ($2.22/share) in the first quarter of 2008. Lower upstream realized prices and volumes[1], decreased Downstream margins[2], higher operating, general and administrative (G&A), depreciation, depletion and amortization (DD&A) and exploration and other[3] expenses resulted in a net loss in the first quarter of 2009.

1 Upstream volumes included the portion of DD&A expense associated with changes in upstream production levels.
2 Downstream margin and volume included the impact on realized margins from fluctuating crude oil feedstock costs while using a "first-in, first-out" (FIFO) inventory valuation methodology.
3 Other mainly included foreign currency translation ($(41) million), interest expense ($(22) million), changes in effective tax rates ($(21) million), insurance proceeds and premium surcharges ($(29) million), upstream inventory movements ($(40) million), mark-to-market valuation of stock-based compensation ($(93) million) and charges due to the deferral of the Fort Hills final investment decision (FID) ($(46) million).

Net Earnings by Segment
(millions of Canadian dollars, after-tax)



The net loss in the first quarter of 2009, compared with net earnings in the first quarter of 2008, on a segmented basis reflected net losses in North American Natural Gas, Oil Sands and Shared Services and Eliminations, as well as decreased net earnings in East Coast Canada, International and the Downstream.

During the first quarter of 2009, cash flow from operating activities was $472 million ($0.97/share), down from $1,435 million ($2.96/share) in the same quarter of 2008. The decrease in cash flow from operating activities primarily reflected the net loss in the current quarter.

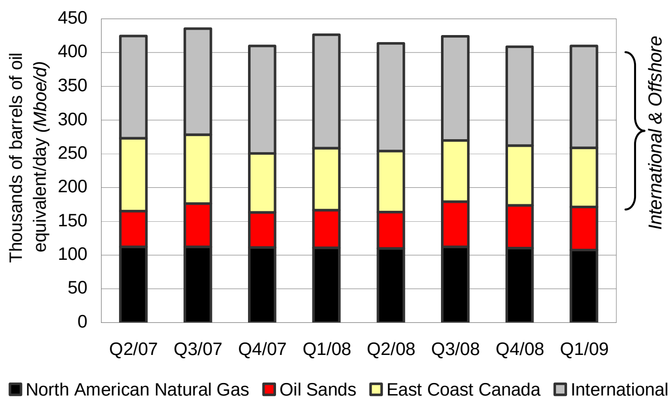
Quarterly Financial Information

(millions of Canadian dollars, except per share amounts)	Three months ended March 31 2009	Dec. 31 2008	Sept. 30 2008	June 30 2008	March 31 2008	Dec. 31 2007	Sept. 30 2007	June 30 2007
Total revenue	**$ 3,971**	$ 5,267	$ 8,286	$ 7,646	$ 6,586	$ 5,434	$ 5,497	$ 5,478
Net earnings (loss)	**$ (47)**	$ (691)	$ 1,251	$ 1,498	$ 1,076	$ 522	$ 776	$ 845
Per share – basic	**(0.10)**	(1.43)	2.58	3.10	2.22	1.08	1.59	1.71
– diluted	**(0.10)**	(1.43)	2.56	3.07	2.20	1.07	1.58	1.70

UPSTREAM

Production

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



In the first quarter of 2009, production averaged 410,000 barrels of oil equivalent/day (boe/d) net to Petro-Canada, down from 427,000 boe/d net in the same quarter of 2008. Volumes reflected decreased North American Natural Gas, East Coast Canada and International production, partially offset by increased Oil Sands production.

Exploration Update

In the first quarter of 2009, Petro-Canada and its partners finished operations on five wells of the up to 12 wells planned in 2009. One well was completed as a gas discovery (L6-7 in the Netherlands sector of the North Sea). This well was started in 2008 but was completed in the first quarter of 2009. One well was completed as an oil discovery (Hobby in the U.K. sector of the North Sea). As a result of the discovery, three sidetracks are planned from this wellbore, of which one has been completed so far. The three wells drilled in Alaska (Chandler 1, Wolf Creek 4 and Gubik 4) all encountered natural gas. Drilling operations were completed for the Wolf Creek and Gubik wells so they were plugged and abandoned. The Chandler well was suspended for possible future testing. These wells are part of a multi-season program and the results are being evaluated for incorporation into an overall plan to determine the commerciality of natural gas development in the region.

North American Natural Gas

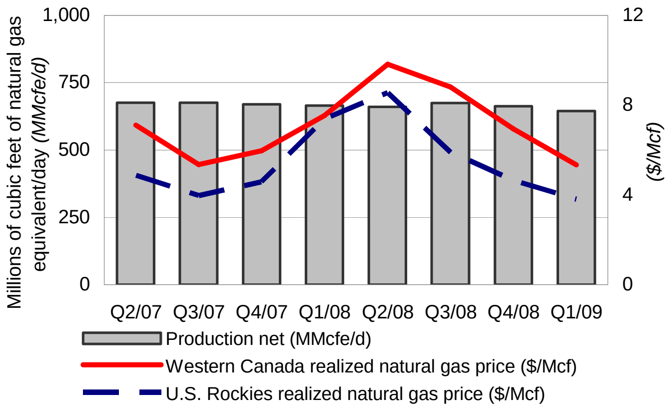
North American Natural Gas facilities continued to operate reliably in the first quarter of 2009.

(millions of Canadian dollars)	Three months ended March 31, 2009	2008
Net earnings (loss)	**$ (2)**	$ 74
Cash flow from operating activities	**$ 59**	$ 199

North American Natural Gas recorded a net loss of $2 million in the first quarter of 2009, compared with net earnings of $74 million in the first quarter of 2008. Lower realized prices and volumes, combined with increased DD&A expense were partially offset by lower exploration expense.

Net earnings in the first quarter of 2008 included a DD&A charge of $24 million after-tax for accumulated project development costs relating to the proposed liquefied natural gas (LNG) re-gasification facility at Gros-Cacouna, Quebec, which has been postponed due to global LNG business conditions.

North American Natural Gas Production and Pricing



In the first quarter of 2009, North American Natural Gas production declined by 3%, compared with the same period in 2008. Decreased production reflected reduced capital spending and natural declines.

Realized natural gas prices in Western Canada and the U.S. Rockies decreased 29% and 48%, respectively, in the first quarter of 2009, compared with the same quarter of 2008, consistent with market price trends.

	First Quarter 2009	First Quarter 2008
Production net *(MMcfe/d)* [1]		
Western Canada	**542**	561
U.S. Rockies	**103**	104
Total North American Natural Gas production net	**645**	665
Western Canada realized natural gas price *(Cdn$/Mcf)* [1]	**$5.34**	$7.53
U.S. Rockies realized natural gas price *(Cdn$/Mcf)* [1]	**$3.81**	$7.38

1 For North American Natural Gas crude oil and NGL production and average realized prices, refer to the charts on pages 19 and 20, respectively.

Petro-Canada gas production operations in Western Canada delivered 99% reliability in the first quarter of 2009.

Scheduled Turnarounds

No major turnarounds are planned at the Company's natural gas processing facilities in the second quarter of 2009.

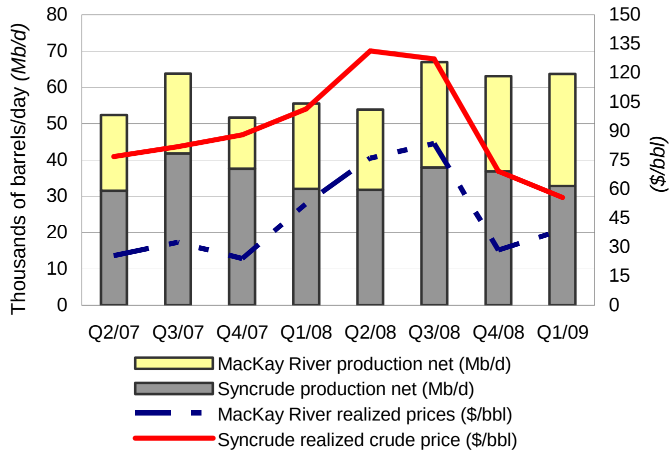
Oil Sands

Strong reliability and increased capability at MacKay River were offset by lower prices.

(millions of Canadian dollars)	**Three months ended March 31, 2009**	2008
Net earnings (loss)	**$ (68)**	$ 112
Cash flow from operating activities	**$ 25**	$ 166

In the first quarter of 2009, Oil Sands recorded a net loss of $68 million, compared with net earnings of $112 million in the first quarter of 2008. Lower realized prices and higher operating, DD&A and exploration expenses were partially offset by higher production. The net loss in the first quarter of 2009 included expenses of $80 million before-tax ($56 million after-tax) to reflect further costs incurred terminating certain goods and services agreements and DD&A charges on certain property, plant and equipment due to the deferral of the Fort Hills FID.

Oil Sands Production and Pricing



Syncrude production was relatively unchanged in the first quarter of 2009, compared with the first quarter of 2008. Production in the current quarter was reduced by bitumen production constraints and the start of an earlier than planned turnaround of Coker 8-3. Production in the first quarter of 2008 was reduced by severe winter weather. Syncrude realized prices were 45% lower in the first quarter of 2009, compared with the first quarter of 2008.

MacKay River production was up 31% in the first quarter of 2009, compared with the same period of 2008, due to strong reliability and increased capability. The Suncor processing agreement commenced on January 1, 2009, allowing MacKay River to realize a combined sour synthetic crude oil and bitumen price in the first quarter of 2009 as opposed to a bitumen-only price in previous quarters. MacKay River combined realized prices averaged $38.76/bbl in the first quarter of 2009, compared with average bitumen prices of $52.43/bbl in the first quarter of 2008.

	First Quarter 2009	First Quarter 2008
Production net *(b/d)*		
Syncrude	**32,800**	32,000
MacKay River [1]	**30,900**	23,500
Total Oil Sands production net	**63,700**	55,500
Syncrude realized crude price *($/bbl)*	**$55.68**	$101.27
MacKay River realized prices *($/bbl)* [1]	**$38.76**	$52.43

1 MacKay River realized prices for 2009 reflect a combination of a sour synthetic price through the Suncor processing arrangement and a bitumen price, while 2008 prices exclusively reflect a bitumen price. Reported production reflects bitumen barrels for both 2009 and 2008.

In the first quarter of 2009, operations at MacKay River continued to be excellent, with increased capability and reliability averaging 98%. As a result, MacKay River achieved record production in the current quarter, averaging 30,900 b/d.

Syncrude's production continued to be negatively impacted by lower than planned bitumen production constraints. While initiatives are being put in place to resolve the current constraints, production is expected to be negatively impacted for the remainder of 2009. The turnaround of Coker 8-3 began a month earlier than planned due to operating difficulties.

Fort Hills Project

The mining portion of the project continues to be on hold until costs can be reduced, commodity prices and financial markets stabilize and the planned merger with Suncor is finalized. The Fort Hills Energy Limited Partnership (FHELP) is deferring the upgrader at this time to reduce overall cost exposure on the project.

Activities during the quarter focused on opportunities for improvement in all areas, including reducing capital and operating costs, achieving efficiencies on project execution and adjusting the overall project schedule for bitumen production. Once this work is complete, the FHELP will develop a definitive cost estimate. While new orders for equipment and services have been put on hold, some long-lead equipment currently on order remains on order, with plans to take delivery and put into storage. Some existing equipment supply and services agreements have been terminated or suspended.

The FHELP reached an agreement with the Government of Alberta to extend the term of the Fort Hills oil sands leases until 2019. As part of the terms of the lease extensions, the FHELP has committed to upgrading the bitumen produced from the second phase of the Fort Hills project in Alberta.

Regulatory approval and Order in Council for the Sturgeon Upgrader was received from the Energy Resources Conservation Board in January 2009. In the fourth quarter of 2008, the Partnership received regulatory approval for an amendment to the approved mine plan, which incorporates improvements identified through the mine plan optimization process.

MacKay River Expansion Project

In the first quarter of 2008, the Company received regulatory approval for the proposed MacKay River 40,000 b/d *in situ* expansion project. The project was put on hold and work has slowed down until costs can be reduced, commodity prices and financial markets stabilize and the planned merger with Suncor is finalized.

Scheduled Turnarounds

Syncrude is expected to complete the planned Coker 8-3 turnaround in the second quarter of 2009. Production at MacKay River will be impacted in the third quarter of 2009 by planned maintenance of the third-party cogeneration unit.

International & Offshore

East Coast Canada

The White Rose Extensions project advanced with development drilling, procurement and fabrication for the North Amethyst portion of the field.

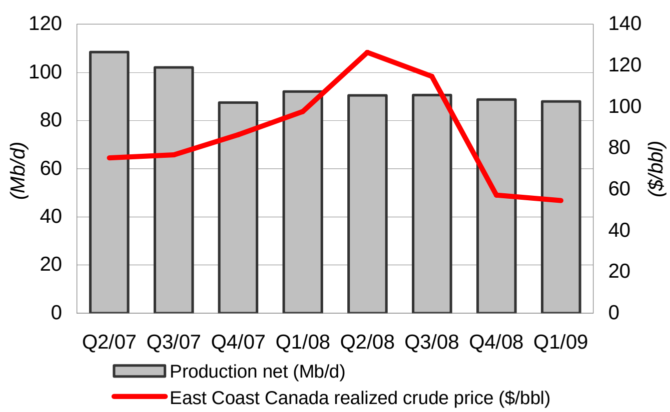
(millions of Canadian dollars)	Three months ended March 31, **2009**	2008
Net earnings [1]	**$ 104**	$ 375
Cash flow from operating activities	**$ 249**	$ 485

1 East Coast Canada crude oil inventory movements decreased net earnings by $39 million before-tax ($27 million after-tax) for the three months ended March 31, 2009. The same factor decreased net earnings by $6 million before-tax ($4 million after-tax) for the three months ended March 31, 2008.

Net earnings for East Coast Canada were $104 million in the first quarter of 2009, down from $375 million in the first quarter of 2008. Lower realized prices and production were partially offset by lower DD&A expense.

Net earnings in the first quarter of 2008 included $29 million in insurance proceeds related to mechanical failures at Terra Nova.

East Coast Canada Production and Pricing



In the first quarter of 2009, East Coast Canada production decreased 5%, compared with the same period in 2008. Hibernia production was slightly higher due to the positive impact of recent well workovers, strong reliability and the addition of a new production well, which offset natural declines. White Rose production was higher due to the completion of a 13-day turnaround in the first quarter of 2008. Terra Nova production was lower due to natural declines.

During the first quarter of 2009, East Coast Canada realized crude prices decreased 44%, compared with the first quarter of 2008.

	First Quarter 2009	First Quarter 2008
Production net *(b/d)*		
Terra Nova	**34,500**	40,100
Hibernia	**27,000**	26,600
White Rose	**26,400**	25,400
Total East Coast Canada production net	**87,900**	92,100
Average realized crude price *($/bbl)*	**$54.65**	$97.70

The Terra Nova Floating Production Storage and Offloading (FPSO) vessel operated at 96% facility reliability in the first quarter of 2009. Performance of the Terra Nova FPSO swivel was unchanged in the first quarter of 2009. All equipment and materials are in place to repair or replace the swivel, if necessary.

Scheduled Turnarounds

The Hibernia planned 21-day turnaround has been delayed until the second quarter of 2009.

Terra Nova is planning a nine-day turnaround in the second quarter of 2009 to do regular emergency systems testing and a 21-day turnaround in the third quarter of 2009 to complete the planned regulatory and maintenance scope.

White Rose is planning a 28-day regulatory and maintenance turnaround in the third quarter of 2009 followed by a further period of reduced production, lasting approximately 40 days, to do subsea work associated with the tie-in of the North Amethyst project.

White Rose Extensions Development

Early in the second quarter of 2008, Petro-Canada and its partners received regulatory approval for the North Amethyst development, and the Company internally approved the project to proceed. Detailed engineering for the North Amethyst portion of the project is complete. Development drilling has commenced and procurement and fabrication for the project continued to advance, with the project on schedule to deliver first oil in late 2009 or early 2010. North Amethyst is the first of three identified extensions to the original White Rose field. Concept selection is ongoing for the West White Rose satellite.

Hebron

During the third quarter of 2008, the Hebron partners reached an agreement with the provincial government on commercial terms that will allow development activities to proceed for Hebron. The transfer of operatorship from Chevron Canada Ltd. to ExxonMobil Canada Properties was effective in the fourth quarter of 2008. During the first quarter of 2009, pre-front-end engineering and design (pre-FEED) activities continued and the Hebron project description was submitted to the Canada-Newfoundland Labrador Offshore Petroleum Board in March 2009. ExxonMobil will open a Hebron project office in the second quarter of 2009.

East Coast Canada Royalties

In the first quarter of 2009, East Coast Canada royalties averaged 25% of gross revenue, compared with 22% in the first quarter of 2008. Terra Nova production was subject to a Tier I royalty of 30% of net revenue and a Tier II royalty of an incremental 12.5% of net revenue, which was triggered during the second quarter of 2008. White Rose production was subject to a Tier I royalty of 20% of net revenue and a Tier II royalty of an incremental 10% of net revenue, which was triggered during the first quarter of 2008. Production from Hibernia continued to be subject to basic royalties of 5% of gross revenue however, provincial government royalty rates are expected to increase from 5% of gross to 30% of net revenue in the near future. In addition, Hibernia production was subject to a federal government net profits interest of up to 10% of net revenue commencing in the first quarter of 2009.

International

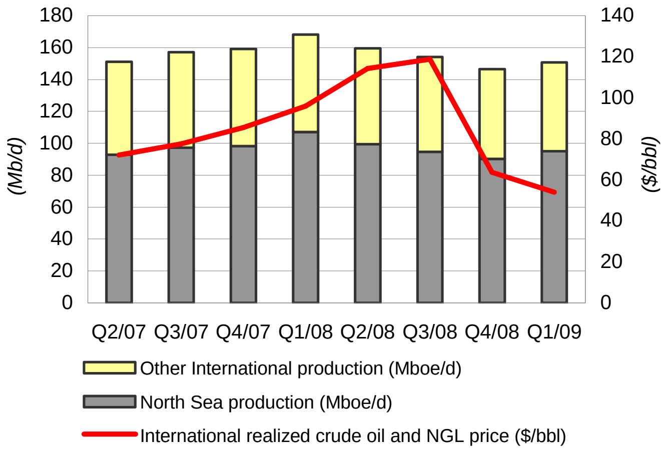
The business had a strong operational quarter, with robust operating performance at Buzzard. The development of the Syria Ebla gas project continues on schedule and on budget.

	Three months ended March 31,	
(millions of Canadian dollars)	**2009**	2008
Net earnings [1]	**$ 41**	$ 336
Cash flow from operating activities	**$ 146**	$ 506

1 International crude oil inventory movements increased net earnings by $2 million before-tax ($1 million after-tax) for the three months ended March 31, 2009. The same factor increased net earnings by $34 million before-tax ($25 million after-tax) for the three months ended March 31, 2008.

In the first quarter of 2009, International delivered net earnings of $41 million, compared with net earnings of $336 million in the first quarter of 2008. Lower realized crude oil prices and decreased production volumes were partially offset by lower operating and exploration expenses.

International Production and Pricing



International production decreased 10% in the first quarter of 2009, compared with the first quarter of 2008.

In the first quarter of 2009, production from the U.K. and the Netherlands sectors of the North Sea decreased by 11%, reflecting an unplanned shutdown of the Triton facility for compressor repairs and natural declines in several North Sea assets. Other International production decreased by 9% in the first quarter of 2009, compared with the first quarter of 2008 due to Organization of the Petroleum Exporting Countries (OPEC) quota constraints imposed in Libya.

	First Quarter 2009	First Quarter 2008
Production net *(boe/d)*		
U.K. sector of the North Sea	**77,600**	84,300
The Netherlands sector of the North Sea	**17,400**	22,800
North Sea	**95,000**	107,100
Other International	**55,700**	61,100
Total International production net	**150,700**	168,200
Average realized crude oil and NGL prices *($/bbl)*	**$53.92**	$95.90
Average realized natural gas price *($/Mcf)*	**$7.99**	$7.99

International operations' realized crude oil and NGL prices decreased 44% in the first quarter of 2009, compared with the same period in 2008. Realized prices for natural gas were unchanged in the first quarter of 2009, compared with the same period in the prior year.

North Sea

Buzzard production averaged 214,100 boe/d gross (64,100 boe/d net) in the first quarter of 2009, up slightly compared with the same quarter of 2008. Work on detailed engineering and ordering of long-lead items is underway for the fourth platform, which is being built to treat higher than expected hydrogen sulphide content in some Buzzard wells. Buzzard is planning a 28-day turnaround in the third quarter of 2009 to do regulatory work and to complete tie-ins for the fourth platform. Production will be reduced for a further 14 days during the third quarter due to maintenance work on the Forties pipeline system.

In the Netherlands sector of the North Sea, the Petro-Canada operated De Ruyter and Hanze facilities continued to perform well, delivering 21,700 boe/d gross (about 11,100 boe/d net) in the first quarter of 2009.

Other International

Production in Libya averaged 43,400 boe/d in the first quarter of 2009, down from 49,800 boe/d in the same quarter of 2008 due to OPEC quota constraints.

Trinidad and Tobago offshore gas production averaged 74 MMcf/d in the first quarter of 2009, up compared with 68 MMcf/d in the first quarter of 2008, reflecting higher demand from the Atlantic LNG terminal and increased field availability.

Syria Ebla Gas Project

The Syria Ebla gas project is expected to produce 80 MMcf/d of natural gas, with first gas anticipated in 2010. The project was 60% complete at the end of the first quarter of 2009. Three wells have been drilled, one of which has been handed over to the engineering, procurement and construction contractor for tie-in.

Libya Exploration and Production Sharing Agreements (EPSAs)

Work has now commenced on implementing the projects associated with the new EPSAs, with a focus on preparing the Amal field development program and initiating the new exploration program. Seismic operations continued in the first quarter of 2009, with four seismic crews deployed. At the end of the first quarter of 2009, the seismic program was approximately 25% complete. The Company expects to begin drilling Petro-Canada's first operated exploration well in the second half of 2009.

In early January 2009, the Libya National Oil Company (NOC) advised the Company that production from Petro-Canada's Libya EPSAs will be limited to 85,000 b/d gross (42,500 b/d net) due to the quota agreed to by OPEC producers in December 2008.

Scheduled Turnarounds

Buzzard is planning a 28-day turnaround in the third quarter of 2009 to do regulatory work and to complete tie-ins for the enhancement project. Production will be reduced for a further 14 days during the third quarter due to maintenance work on the Forties pipeline system.

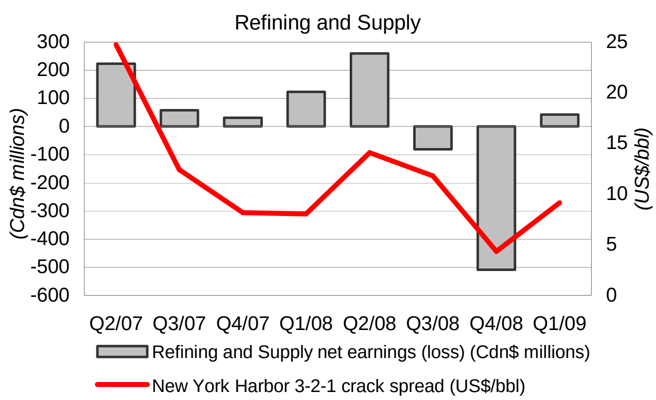
DOWNSTREAM

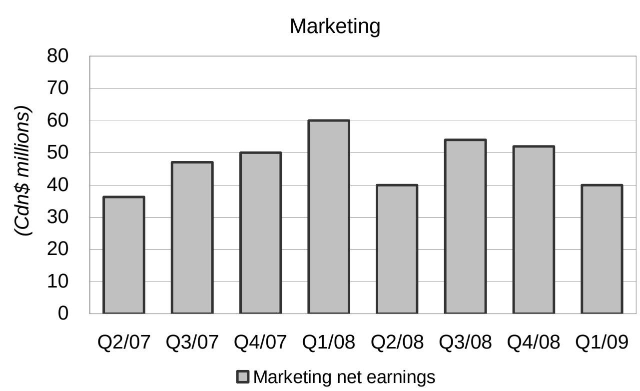
The Downstream continued to ramp up the production of the Edmonton RCP.

(millions of Canadian dollars)	**Three months ended March 31, 2009**	2008
Net earnings	**$ 82**	$ 184
Cash flow from (used in) operating activities	**$ 298**	$ (16)

The Downstream business recorded net earnings of $82 million in the first quarter of 2009, down significantly compared with $184 million in the same quarter of 2008. The impact of fluctuating crude oil feedstock costs while using a FIFO inventory valuation methodology was lower compared with the same period last year. Also negatively impacting earnings were lower distillate cracking margins, unfavourable crude price differentials and lower refinery yields. These factors were partially offset by an increase in realized refining margins, higher gasoline cracking margins and positive foreign exchange impacts.

Downstream Net Earnings





	First Quarter 2009	First Quarter 2008
Refining and Supply net earnings *(millions of Canadian dollars)*	**$42**	$124
New York Harbor 3-2-1 crack spread *(US$/bbl)*	**$9.16**	$8.06
Chicago 3-2-1 crack spread *(US$/bbl)*	**$8.93**	$7.04
Seattle 3-2-1 crack spread *(US$/bbl)*	**$13.44**	$9.53
Marketing net earnings *(millions of Canadian dollars)*	**$40**	$60

The average New York Harbor 3-2-1 refinery crack spread was $9.16 US/bbl in the first quarter of 2009, up from $8.06 US/bbl in the first quarter of 2008. The average international light/heavy crude price differential was $5.89 US/bbl in the first quarter of 2009, compared with $15.77 US/bbl in the first quarter of 2008. The average domestic light/heavy crude price differential was $9.02 US/bbl in the first quarter of 2009, compared with $21.61 US/bbl in the first quarter of 2008.

In the first quarter of 2009, total sales of refined petroleum products decreased 3.3% to 4.6 billion litres, compared with the same period last year. The decrease reflected lower wholesale, lubricants and retail sales volumes, partially offset by higher Refining and Supply sales volumes.

Refining and Supply contributed net earnings of $42 million in the first quarter of 2009, down significantly from net earnings of $124 million in the same quarter of 2008. Results were negatively impacted by the following four factors, listed in order of impact. First, changes in the crude price profile affecting feedstock costs while using a FIFO inventory valuation methodology were lower compared with the same period last year. Second, distillate cracking margins were lower. Third, crude price differentials were unfavourable. Fourth, refinery yields in Edmonton were lower. These factors were partially offset by an increase in realized refining margins for lubricants, asphalt and coke, heavy fuel oil, liquid petroleum gases and light oil products, higher gasoline cracking margins and positive foreign exchange impacts.

Marketing contributed first quarter 2009 net earnings of $40 million, down compared with $60 million in the same quarter of 2008. In the first quarter of 2009, Marketing results reflected the impact of feedstock costs in the Lubricants business related to changes in the crude price profile over the same period last year while using a FIFO inventory valuation methodology and overall lower sales volumes. These factors were partially offset by higher fuel margins.

Edmonton Refinery Conversion Project (RCP)

At the Edmonton refinery, the Company converted the facility to run oil sands-based feedstock. The RCP enables Petro-Canada to directly upgrade up to 26,000 b/d of bitumen and process up to 48,000 b/d of sour synthetic crude oil, replacing the more expensive conventional light crude feedstock previously refined.

The Edmonton refinery continued its ramp up of the RCP in the first quarter of 2009. An operational upset in January 2009 and lower market demand decreased refinery yields at the Edmonton refinery in the quarter.

Montreal Coker

The Montreal coker project is on hold until commodity prices and financial markets stabilize and the planned merger with Suncor is finalized. Activities for the remainder of 2009 are focused on completing most of the engineering, meeting procurement commitments and completing construction to a state that will benefit the refinery regardless of whether the project proceeds. The Company is also continuing to rework the project costs to take advantage of the current market environment.

Downstream Turnaround Activity

In the second quarter of 2009, turnaround and maintenance activities are planned at the Edmonton and Montreal refineries. As with all planned Downstream turnarounds, supply arrangements are in place to meet market demand during these outages.

CORPORATE

Shared Services and Eliminations	**Three months ended March 31,**	
(millions of Canadian dollars)	**2009**	2008
Net loss	**$ (204)**	$ (5)
Cash flow from (used in) operating activities	**$ (305)**	$ 95

Shared Services and Eliminations recorded a net loss of $204 million in the first quarter of 2009, compared with a net loss of $5 million for the same period in 2008. The net loss in the first quarter of 2009 included a $99 million foreign currency translation loss on long-term debt, a $25 million expense related to the mark-to-market valuation of stock-based compensation and a charge of $19 million related to the elimination of profits in the upstream business units for crude oil sales to Downstream where the crude oil still resides in Downstream's inventories. The net loss in the first quarter of 2008 included a $68 million recovery related to the mark-to-market valuation of stock-based compensation, a $48 million foreign currency translation loss on long-term debt and a recovery of $3 million related to the recovery of losses in the upstream business units for crude oil sales to Downstream where the crude oil still resides in Downstream's inventories.

Interest expense was $78 million before-tax ($54 million after-tax) during the first quarter of 2009, up from $48 million before-tax ($33 million after-tax) in the first quarter of the prior year. The Company capitalized $11 million of interest expense during the quarter, compared with $13 million in the first quarter of 2008.

Cash flow from operating activities was affected by tax deferrals resulting from the Company's upstream partnership. These deferrals decreased cash flow from operating activities by about $111 million in the quarter, compared with a decrease of about $1 million in the same period last year.

LIQUIDITY AND CAPITAL RESOURCES

Summary of Cash Flows

(millions of Canadian dollars)	**Three months ended March 31, 2009**	2008
Cash flow from operating activities	**$ 472**	$ 1,435
Net cash (outflows) inflows from:		
Investing activities	**(1,049)**	(970)
Financing activities	**(96)**	(434)
Increase (decrease) in cash and cash equivalents	**(673)**	31
Cash and cash equivalents	**$ 772**	$ 262

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 operating activities and debt-to-debt plus equity. Petro-Canada's debt-to-cash flow from operating activities ratio, a key short-term leverage measure, was 1.1 times at March 31, 2009. This was within the Company's long-term range of no more than 2.0 times. Debt-to-debt plus equity, the long-term measure for capital structure, was 24.2% at March 31, 2009, below the Company's long-term range of 25% to 35%.

Financial Ratios	**March 31, 2009**	December 31, 2008	March 31, 2008
Debt-to-cash flow from operating activities *(times)* [1]	**1.1**	0.7	0.9
Debt-to-debt plus equity *(%)*	**24.2**	23.5	18.9

1 Calculated on a 12-month rolling basis.

Operating Activities

The operating working capital surplus was $477 million at March 31, 2009, excluding cash and cash equivalents, the current portion of long-term debt and short-term notes payable, compared with an operating working capital deficiency of $46 million at December 31, 2008. The increase in operating working capital to a surplus position at March 31, 2009 primarily resulted from a decrease in income taxes payable, as significant Canadian tax instalments were paid during the quarter, and a decrease in accounts payable and accrued liabilities due to a reduction in spending.

Investing Activities

(millions of Canadian dollars)	**Three months ended March 31, 2009**	2008
Upstream		
North American Natural Gas	**$ 95**	$ 167
Oil Sands	**139**	178
International & Offshore		
East Coast Canada	**55**	38
International	**348**	251
	637	634
Downstream		
Refining and Supply	**33**	352
Sales and Marketing	**4**	23
Lubricants	**6**	3
	43	378
Shared Services	**1**	4
Total property, plant and equipment and exploration	**681**	1,016
Other assets	**–**	–
Total capital expenditures	**$ 681**	$ 1,016

Financing Activities

At the end of the first quarter of 2009, the Company's committed credit facilities and bilateral demand facilities totalled $3,822 million and $775 million, respectively, of which $333 million was used for letters of credit and overdraft coverage. The committed facilities are in place until 2013 and the syndicated portion of these facilities, which total $3,570 million, may be used to provide liquidity support to a commercial paper program. The Company does not have any plans to issue commercial paper in the near term and no commercial paper was outstanding at March 31, 2009.

At March 31, 2009, the credit ratings for the Company's unsecured long-term debt were Baa2, developing, by Moody's Investors Service, BBB on credit watch with positive implications by Standard & Poor's and A (low) under review with developing implications by Dominion Bond Rating Service (DBRS). The Company's short-term debt securities are rated R-1 (low) under review with developing implications by DBRS.

The Company's financial capacity and flexibility remain strong despite the recent turmoil in financial markets. This is due to the Company being able to generate cash flow, having access to existing cash balances and significant credit facility capacity and requiring no near-term refinancing. For 2009, the Company expects to cover its capital program with cash flow and, if necessary, from available credit facilities. The Company will monitor energy and financial markets through the year and take advantage of the flexibility in its capital program to pace projects and adjust capital expenditures accordingly.

Returning Cash to Shareholders

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 a share buyback program.

Petro-Canada regularly reviews its dividend strategy to ensure the alignment of dividend policy with shareholder expectations, and financial and growth objectives. Total dividends paid in the first quarter of 2009 were $97 million ($0.20/share), compared with $63 million ($0.13/share) in the same period last year.

Petro-Canada's current NCIB program entitles the Company to repurchase up to 5% of its outstanding common shares from June 22, 2008 to June 21, 2009, subject to certain conditions. In the first quarter of 2009, the Company did not repurchase any of its shares, consistent with the same period last year. Future share repurchases will depend on excess cash available after consideration of the Company's priority uses of cash.

Contingent Liabilities and Contractual Obligations

Contractual obligations are summarized in the Company's 2008 annual MD&A and contingent liabilities are disclosed in Note 28 of the 2008 annual Consolidated Financial Statements. Total contractual obligations at March 31, 2009 were $36.1 billion. During the first quarter of 2009, contractual obligations decreased by $0.9 billion primarily due to decreased product purchase commitments.

The Company has certain retail licensee agreements that qualify as variable interest entities, as described in Note 29 to the 2008 annual Consolidated Financial Statements. These entities were not consolidated as Petro-Canada is not the primary beneficiary and the Company's maximum exposure to losses from these arrangements was not expected to be material.

RISK

Petro-Canada's risk management activities are conducted in accordance with the policies and guidelines established by the Board of Directors. On an ongoing basis, Petro-Canada monitors the risks facing the Company, identifies emerging risks and assesses the adequacy of mitigation efforts. Readers should refer to Petro-Canada's 2008 AIF and the risk management section of the 2008 annual MD&A for a further discussion of risks relating to Petro-Canada's business.

Merger with Suncor Energy Inc.

On March 23, 2009, Petro-Canada announced its intent to merge with Suncor. The merged company will be subject to certain risks, including those described in the risk sections of the Suncor and Petro-Canada AIFs, as well as risks related to the merger itself. These may include, but are not limited to, the risk that the proposed combination will not be approved by shareholders of either company or by regulatory authorities and the risk that the proposed benefits of the merger will not be realized. The proposed merger is conditional upon approval by shareholders of both companies, compliance with the Competition Act, and satisfaction of other customary approvals including regulatory, stock exchange and Court of Queen's Bench of Alberta approvals.

INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

During 2008, the Canadian Accounting Standards Board (AcSB) confirmed that publicly accountable enterprises will be required to adopt International Financial Reporting Standards (IFRS) in place of Canadian generally accepted accounting principles (GAAP) for interim and annual reporting purposes. The required changeover date is for fiscal years beginning on or after January 1, 2011.

The Company has successfully completed the first and second phases of its IFRS project. This involved the development of a detailed IFRS project plan and team, delivery of education and training sessions throughout the Company and the completion of a comprehensive analysis of the impact of the IFRS differences identified in the initial scoping assessment. In addition, an initial evaluation of IFRS 1 transition exemptions and financial systems was performed.

The Company is currently engaged in the third phase of its IFRS project. During this phase, the Company is implementing the required changes to business processes, financial systems, accounting policies, disclosure controls and internal controls over financial reporting. Regular reporting continues to be provided to the Company's senior executive management and to the Audit, Finance and Risk Committee of the Board of Directors. Education and training sessions for employees are ongoing throughout the implementation phase. New and revised IFRS developments will be monitored.

The Company's IFRS project continues to be on target to meet the changeover date.

SHAREHOLDER INFORMATION

As at March 31, 2009, Petro-Canada's outstanding common shares totalled 484.9 million and averaged 484.8 million during the first quarter of 2009. These figures compare with outstanding common shares of 483.6 million as at March 31, 2008 and average shares outstanding of 484.0 million for the quarter ended March 31, 2008.

Petro-Canada will hold a conference call to discuss these results with investors on Tuesday, April 28, 2009 at 9:00 a.m. eastern daylight time (EDT). To participate, please call 1-800-769-8320 (toll-free in North America), 00-800-4222-8835 (toll-free internationally), or 416-695-6622 at 8:55 a.m. EDT. Media are invited to listen to the call by dialing 1-800-952-4972 (toll-free in North America) or 416-695-7848. Media are invited to ask questions at the end of the call. A live audio broadcast of the conference call will be available on Petro-Canada's website at http://www.petro-canada.ca/en/investors/845.aspx on April 28, 2009 at 9:00 a.m. EDT. Those who are unable to listen to the call live may listen to a recording of the call approximately one hour after its completion by dialing 1-800-408-3053 (toll-free in North America) or 416-695-5800 (pass code number 4003670#). Approximately one hour after the call, a recording will be available on Petro-Canada's website.

SELECT UPSTREAM OPERATING DATA
March 31, 2009

	Three months ended March 31,	
	2009	2008
Before Royalties		
Crude oil and NGL production net *(Mb/d)*		
North American Natural Gas	**13.7**	13.1
Oil Sands	**63.7**	55.5
International & Offshore		
East Coast Canada	**87.9**	92.1
International		
North Sea	**85.6**	97.4
Other International	**43.4**	49.8
	294.3	307.9
Natural gas production net, excluding injectants *(MMcf/d)*		
North American Natural Gas	**563**	586
International		
North Sea	**56**	58
Other International	**74**	68
	693	712
Total production *(Mboe/d)* net before royalties [1]	**410**	427
After Royalties		
Crude oil and NGL production net *(Mb/d)*		
North American Natural Gas	**10.2**	10.0
Oil Sands	**63.0**	50.6
International & Offshore		
East Coast Canada	**66.1**	72.1
International		
North Sea	**85.6**	97.4
Other International	**18.4**	45.8
	243.3	275.9
Natural gas production net, excluding injectants *(MMcf/d)*		
North American Natural Gas	**474**	466
International		
North Sea	**56**	58
Other International	**74**	68
	604	592
Total production *(Mboe/d)* net after royalties [1]	**344**	375

1 Natural gas converted at six Mcf of natural gas to one bbl of oil.

AVERAGE UPSTREAM PRICE REALIZED
March 31, 2009

	Three months ended March 31,	
	2009	2008
Crude oil and NGL *($/bbl)*		
North American Natural Gas	**44.34**	89.23
Oil Sands	**47.47**	80.61
International & Offshore		
East Coast Canada	**54.65**	97.70
International		
North Sea	**54.03**	94.31
Other International	**52.84**	99.13
Total crude oil and NGL	**52.08**	93.38
Natural gas *($/Mcf)*		
North American Natural Gas	**5.14**	7.51
International		
North Sea	**11.92**	10.77
Other International	**4.09**	4.95
Total natural gas	**5.62**	7.59

EFFECTIVE ROYALTY RATES
March 31, 2009

	Three months ended March 31,	
(% of sales revenues)	**2009**	2008
North American Natural Gas	**17%**	21%
Oil Sands	**1%**	9%
International & Offshore		
East Coast Canada	**25%**	22%
International		
North Sea	**–**	–
Other International [1]	**45%**	7%
Total	**16%**	12%

1 Increased royalty rates reflect a portion of the NOC's take under the new Libya EPSAs and should be read in conjunction with the updated March 2009 Libya EPSAs Fact Sheet.

SELECT DOWNSTREAM OPERATING DATA
March 31, 2009

	Three months ended March 31, **2009**	2008
Petroleum product sales *(thousands of cubic metres/day – m^3/d)*		
Gasoline		
Eastern Canada	**13.5**	12.8
Western Canada	**9.7**	10.8
	23.2	23.6
Distillates		
Eastern Canada	**8.8**	8.9
Western Canada	**9.3**	10.8
	18.1	19.7
Other, including petrochemicals	**9.8**	8.9
Total petroleum product sales	**51.1**	52.2
Crude oil processed by Petro-Canada *(thousands of m^3/d)*		
Eastern Canada	**20.3**	19.7
Western Canada	**15.5**	21.1
Total crude oil processed by Petro-Canada	**35.8**	40.8
Average refinery utilization *(%)*	**88**	101
Downstream net earnings after-tax *(cents/litre)*	**1.8**	3.9

AVERAGE DOWNSTREAM PRICES
March 31, 2009

	Three months ended March 31, **2009**	2008
Rack prices *(Canadian cents/litre)*		
Gasoline		
Eastern Canada	**46.75**	70.82
Western Canada	**48.81**	70.15
Distillate		
Eastern Canada	**54.64**	81.62
Western Canada	**50.50**	80.61
Pump prices (*Canadian cents/litre, excluding taxes*)		
Gasoline		
Eastern Canada	**53.49**	76.23
Western Canada	**58.89**	80.02

SHARE INFORMATION
March 31, 2009

		Three months ended March 31, 2009	2008
Weighted-average common shares outstanding *(millions)*		**484.8**	484.0
Weighted-average diluted common shares outstanding *(millions)* [1]		**484.8**	488.0
Net earnings (loss)	– basic *($/share)*	**(0.10)**	2.22
	– diluted *($/share)*	**(0.10)**	2.20
Dividends *($/share)*		**0.20**	0.13
Toronto Stock Exchange:			
Share price [2]	– High	**35.70**	55.35
	– Low	**24.88**	42.77
	– Close at March 31	**33.87**	44.72
Shares traded *(millions)*		**174.6**	155.9
New York Stock Exchange:			
Share price [3]	– High	**29.29**	55.99
	– Low	**19.46**	41.95
	– Close at March 31	**26.58**	43.41
Shares traded *(millions)*		**191.5**	86.0

1 Diluted common shares outstanding exclude 1.7 million stock options for the three months ended March 31, 2009 because their impact was anti-dilutive. See Note 5 to the unaudited Consolidated Financial Statements for the three months ended March 31, 2009.
2 Share price is in Canadian dollars and represents the closing price.
3 Share price is in U.S. dollars and represents the closing price.

SELECT FINANCIAL DATA
March 31, 2009
(unaudited, millions of Canadian dollars)

	Three months ended March 31, 2009	2008
Net earnings (loss)		
Upstream		
North American Natural Gas	**$ (2)**	$ 74
Oil Sands	**(68)**	112
International & Offshore		
East Coast Canada	**104**	375
International	**41**	336
Downstream	**82**	184
Shared Services	**(204)**	(5)
Net earnings (loss)	**$ (47)**	$ 1,076
Cash flow from operating activities	**$ 472**	$ 1,435
Average capital employed [1]		
Upstream	**$ 10,807**	$ 9,103
Downstream	**7,239**	5,862
Shared Services	**457**	275
Total Company	**$ 18,503**	$ 15,240
Return on capital employed *(%)* [1]		
Upstream	**26.9**	28.4
Downstream	**(1.4)**	10.7
Total Company	**10.2**	21.9
Return on equity *(%)* [1]	**13.9**	26.2
Debt	**$ 4,890**	$ 3,176
Cash and cash equivalents	**$ 772**	$ 262
Debt-to-cash flow from operating activities *(times)* [1]	**1.1**	0.9
Debt-to-debt plus equity *(%)*	**24.2**	18.9

1 Calculated on a 12-month rolling basis.

CONSOLIDATED STATEMENT OF EARNINGS *(unaudited)*
For the periods ended March 31
(millions of Canadian dollars, except per share amounts)

	Three months ended March 31,	
	2009	2008
Revenue		
Operating	$ 3,971	$ 6,617
Investment and other income (expense) *(Note 3)*	-	(31)
	3,971	6,586
Expenses		
Crude oil and product purchases	1,956	2,963
Operating, marketing and general *(Note 4)*	1,051	843
Exploration	108	143
Depreciation, depletion and amortization *(Note 4)*	560	523
Unrealized loss on translation of foreign currency denominated long-term debt	103	55
Interest	78	48
	3,856	4,575
Earnings before income taxes	115	2,011
Provision for income taxes		
Current	191	844
Future	(29)	91
	162	935
Net earnings (loss)	$ (47)	$ 1,076
Earnings per share *(Note 5)*		
Basic	$ (0.10)	$ 2.22
Diluted	$ (0.10)	$ 2.20

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME *(unaudited)*
For the periods ended March 31
(millions of Canadian dollars)

	Three months ended March 31,	
	2009	2008
Net earnings (loss)	$ (47)	$ 1,076
Other comprehensive income (loss), net of tax		
Change in foreign currency translation adjustment	(41)	207
Comprehensive income (loss)	$ (88)	$ 1,283

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENT OF CASH FLOWS *(unaudited)*
For the periods ended March 31
(millions of Canadian dollars)

	Three months ended March 31,	
	2009	2008
Operating activities		
Net earnings (loss)	$ (47)	$ 1,076
Items not affecting cash flow from operating activities:		
Depreciation, depletion and amortization *(Note 4)*	560	523
Future income taxes	(29)	91
Accretion of asset retirement obligations	21	19
Unrealized loss on translation of foreign currency denominated long-term debt	103	55
Gain on sale of assets	(1)	(4)
Other	61	11
Exploration expenses	34	81
Increase in non-cash working capital related to operating activities	(230)	(417)
Cash flow from operating activities	472	1,435
Investing activities		
Expenditures on property, plant and equipment and exploration	(681)	(1,016)
Proceeds from sale of assets	3	12
(Increase) decrease in non-cash working capital related to investing activities	(371)	34
Cash flow used in investing activities	(1,049)	(970)
Financing activities		
Increase in short-term notes payable	-	322
Repayment of long-term debt	(1)	(696)
Proceeds from issue of common shares	2	3
Dividends on common shares	(97)	(63)
Cash flow used in financing activities	(96)	(434)
Increase (decrease) in cash and cash equivalents	(673)	31
Cash and cash equivalents at beginning of period	1,445	231
Cash and cash equivalents at end of period	$ 772	$ 262

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED BALANCE SHEET *(unaudited)*
As at March 31, 2009
(millions of Canadian dollars)

	March 31, 2009	December 31, 2008
Assets		
Current assets		
Cash and cash equivalents	$ 772	$ 1,445
Accounts receivable	2,864	2,844
Inventories	1,358	1,289
Future income taxes	32	25
	5,026	5,603
Property, plant and equipment, net	23,629	23,485
Goodwill	845	852
Other assets	436	437
	$ 29,936	$ 30,377
Liabilities and shareholders' equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 3,070	$ 3,186
Income taxes payable	707	1,018
Current portion of long-term debt	3	3
	3,780	4,207
Long-term debt *(Note 6)*	4,887	4,746
Other liabilities	1,225	1,240
Asset retirement obligations	1,590	1,527
Future income taxes	3,163	3,182
Shareholders' equity		
Common shares	1,390	1,388
Contributed surplus	21	22
Retained earnings	13,918	14,062
Accumulated other comprehensive income (loss)		
Foreign currency translation adjustment	(38)	3
	15,291	15,475
	$ 29,936	$ 30,377

CONSOLIDATED STATEMENT OF RETAINED EARNINGS *(unaudited)*
For the periods ended March 31
(millions of Canadian dollars)

	Three months ended March 31,	
	2009	2008
Retained earnings at beginning of period	$ 14,062	$ 11,248
Net earnings (loss)	(47)	1,076
Dividends on common shares	(97)	(63)
Retained earnings at end of period	$ 13,918	$ 12,261

See accompanying Notes to Consolidated Financial Statements

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

1. SEGMENTED INFORMATION FROM OPERATIONS
Three months ended March 31,

	Upstream															
					International & Offshore											
	North American Natural Gas		Oil Sands		East Coast Canada		International		Downstream		Shared Services		Eliminations[3]		Consolidated	
	2009	2008	2009	2008	2009	2008	2009	2008	2009	2008	2009	2008	2009	2008	2009	2008
Revenue																
Sales to customers	$ 326	$ 430	$ 222	$ 345	$ 315	$ 682	$ 618	$ 1,394	$ 2,490	$ 3,766	$ -	$ -	$ -	$ -	$ 3,971	$ 6,617
Investment and other income (expense)	(1)	3	-	2	2	1	(24)	(31)	10	(8)	13	2	-	-	-	(31)
Inter-segment sales	66	99	300	297	87	204	8	-	2	4	-	-	(463)	(604)	-	-
Segmented revenue	391	532	522	644	404	887	602	1,363	2,502	3,762	13	2	(463)	(604)	3,971	6,586
Expenses																
Crude oil and product purchases[1]	88	93	274	248	114	188	-	-	1,453	2,439	-	-	27	(5)	1,956	2,963
Inter-segment transactions	1	2	10	8	1	2	-	-	451	592	-	-	(463)	(604)	-	-
Operating, marketing and general	136	128	273	204	50	57	137	130	403	404	52	(80)	-	-	1,051	843
Exploration	20	50	29	5	1	-	58	88	-	-	-	-	-	-	108	143
Depreciation, depletion and amortization	160	154	39	27	90	97	171	170	100	75	-	-	-	-	560	523
Unrealized loss on translation of foreign currency denominated long-term debt	-	-	-	-	-	-	-	-	-	-	103	55	-	-	103	55
Interest	-	-	-	-	-	-	-	-	-	-	78	48	-	-	78	48
	405	427	625	492	256	344	366	388	2,407	3,510	233	23	(436)	(609)	3,856	4,575
Earnings (loss) before income taxes	(14)	105	(103)	152	148	543	236	975	95	252	(220)	(21)	(27)	5	115	2,011
Provision for income taxes																
Current	51	27	(4)	15	45	177	204	647	(76)	23	(29)	(47)	-	2	191	844
Future	(63)	4	(31)	25	(1)	(9)	(9)	(8)	89	45	(6)	34	(8)	-	(29)	91
	(12)	31	(35)	40	44	168	195	639	13	68	(35)	(13)	(8)	2	162	935
Net earnings (loss)	$ (2)	$ 74	$ (68)	$ 112	$ 104	$ 375	$ 41	$ 336	$ 82	$ 184	$ (185)	$ (8)	$ (19)	$ 3	$ (47)	$ 1,076
Expenditures on property, plant and equipment and exploration [2]	$ 95	$ 167	$ 139	$ 178	$ 55	$ 38	$ 348	$ 251	$ 43	$ 378	$ 1	$ 4	$ -	$ -	$ 681	$ 1,016
Cash flow from (used in) operating activities	$ 59	$ 199	$ 25	$ 166	$ 249	$ 485	$ 146	$ 506	$ 298	$ (16)	$ (305)	$ 95	$ -	$ -	$ 472	$ 1,435
Total assets	$ 4,517	$ 4,179	$ 4,678	$ 3,936	$ 2,074	$ 2,352	$ 8,117	$ 6,058	$10,057	$ 9,677	$ 523	$ 37	$ (30)	$ (110)	$29,936	$26,129

1 Downstream crude oil and product purchases accounts for substantially all of the Downstream inventories recognized as an expense during the period.
2 Consolidated expenditures include capitalized interest in the amount of $11 million for the three months ended March 31, 2009 ($13 million for the three months ended March 31, 2008).
3 Eliminations relate to sales between segments recorded at transfer prices based on current market prices, and to unrealized inter-segment profits in inventories.

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

2. BASIS OF PRESENTATION

The note disclosure requirements for annual financial statements provide additional disclosure to that required for interim financial statements. Accordingly, these interim Consolidated Financial Statements should be read in conjunction with the December 31, 2008 audited Consolidated Financial Statements. The interim Consolidated Financial Statements are presented in accordance with Canadian generally accepted accounting principles (GAAP) and follow the accounting policies summarized in the notes to the annual Consolidated Financial Statements.

3. INVESTMENT AND OTHER INCOME (EXPENSE)

Investment and other income (expense) consists of the following amounts:

	Three months ended March 31,	
	2009	2008
Foreign exchange losses	$ (6)	$ (22)
Gain (loss) on Downstream derivative contracts	5	(13)
Gain on sale of assets	1	4
Total investment and other income (expense)	$ -	$ (31)

4. FORT HILLS PROJECT

In November 2008, the Company and its partners, UTS Energy Corporation (UTS) and Teck Cominco Limited (Teck), announced that the preliminary results from the Fort Hills project front-end engineering and design (FEED) work suggest that estimated costs have risen considerably and, therefore, a final investment decision (FID) on both the mining and upgrading portions of the project would be deferred until a cost estimate consistent with the current market environment can be established.

During the first quarter of 2009, the Company focused activities on opportunities for improvement in all areas, including capital and operating cost reductions, efficiencies on project execution and the overall project schedule for bitumen production. As a result, for the three months ended March 31, 2009, the Company recognized a $14 million ($10 million after-tax) impairment charge on certain property, plant and equipment and expenses of $66 million ($46 million after-tax) to reflect the termination or suspension of some agreements for the receipt of goods and services.

The impairment charge is included in depreciation, depletion and amortization and the costs of terminating the goods and services agreements are included in operating, marketing and general expenses, both on the Consolidated Statement of Earnings.

5. EARNINGS PER SHARE

The following table provides the number of common shares used in calculating earnings per share amounts:

	Three months ended March 31,	
(millions)	2009	2008
Weighted-average number of common shares outstanding – basic	484.8	484.0
Effect of dilutive stock options[1]	0.0	4.0
Weighted-average number of common shares outstanding – diluted	484.8	488.0

1 1.7 million stock options were excluded from the diluted common shares outstanding calculation for the three months ended March 31, 2009 because their impact was anti-dilutive (nil for the three months ended March 31, 2008).

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

6. LONG-TERM DEBT

	Maturity	March 31, 2009	December 31, 2008
Debentures and notes			
6.80% unsecured senior notes ($900 million US)	2038	$ 1,122	$ 1,090
5.95% unsecured senior notes ($600 million US)	2035	740	719
5.35% unsecured senior notes ($300 million US)	2033	331	320
7.00% unsecured debentures ($250 million US)	2028	305	296
7.875% unsecured debentures ($275 million US)	2026	342	332
9.25% unsecured debentures ($300 million US)	2021	376	365
6.05% unsecured debentures ($600 million US)	2018	750	729
5.00% unsecured senior notes ($400 million US)	2014	500	485
4.00% unsecured senior notes ($300 million US)	2013	362	351
Capital leases	2009-2022	62	62
		4,890	4,749
Current portion		(3)	(3)
		$ 4,887	$ 4,746

Interest on long-term debt and short-term notes payable, net of capitalized interest, was $76 million for the three months ended March 31, 2009 ($46 million for the three months ended March 31, 2008). Interest is paid semi-annually. All debentures and notes are repayable in full upon maturity.

The Company had in place the following revolving credit facilities:

Facility	Maturity	March 31, 2009	December 31, 2008
Syndicated, committed	2013	$ 3,570	$ 3,570
Bilateral, committed ($200 million US)[1]	2013	252	-
Bilateral, demand	n/a	775	777
Total available credit facilities		4,597	4,347
Used for letters of credit and overdraft coverage		(333)	(348)
Total credit facilities not used [2]		$ 4,264	$ 3,999

1 Use of this facility is restricted to business activities outside of Canada.
2 Excludes $500 million capacity available under accounts receivable securitization program.

7. SHAREHOLDERS' EQUITY

Changes in common shares and contributed surplus were as follows:

	Shares	Amount	Contributed Surplus
Balance at December 31, 2008	484,597,467	$ 1,388	$ 22
Issued under employee stock option and share purchase plans	274,194	2	(1)
Balance at March 31, 2009	484,871,661	$ 1,390	$ 21

The Company has in place a normal course issuer bid (NCIB) program for the repurchase of up to 24 million of its outstanding common shares during the period from June 22, 2008 to June 21, 2009, subject to certain conditions. During the three months ended March 31, 2009 and March 31, 2008, the Company did not repurchase any common shares.

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

8. STOCK-BASED COMPENSATION

Stock-based compensation expense was $39 million for the three months ended March 31, 2009 and a recovery of $(97) million for the three months ended March 31, 2008.

(a) Stock Options

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

	Stock Options	
	Number	Weighted-Average Exercise Price
Balance at December 31, 2008	22,133,902	$ 37
Granted	2,703,900	25
Exercised for common shares	(274,194)	10
Surrendered for cash payment	(15,250)	30
Forfeited	(161,700)	39
Expired	(2,000)	8
Balance at March 31, 2009	24,384,658	$ 36

(b) Stock Appreciation Rights (SARs)

Changes in the number of outstanding SARs were as follows:

	SARs	
	Number	Weighted-Average Exercise Price
Balance at December 31, 2008	7,207,354	$ 46
Granted	5,445,450	25
Exercised	-	-
Forfeited	(60,337)	43
Balance at March 31, 2009	12,592,467	$ 37

(c) Performance Share Units (PSUs)

Changes in the number of outstanding PSUs were as follows:

	PSUs
	Number
Balance at December 31, 2008	828,372
Granted	255,137
Redeemed	(348,980)
Forfeited	(1,219)
Balance at March 31, 2009	733,310

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

8. STOCK-BASED COMPENSATION *continued*

(d) Restricted Stock Units (RSUs)

During the quarter, the Company instituted an RSU plan for senior management employees, whereby 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 and the value of notional dividends applied during the period.

Changes in the number of outstanding RSUs were as follows:

	RSUs
	Number
Balance at December 31, 2008	-
Granted	808,560
Redeemed	-
Forfeited	(2,059)
Balance at March 31, 2009	806,501

9. 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 March 31,	
	2009	2008
Pension Plans:		
Defined benefit plans		
Employer current service cost	$ 8	$ 11
Interest cost	26	23
Expected return on plan assets	(22)	(28)
Amortization of transitional asset	(1)	(1)
Amortization of net actuarial losses	18	12
	29	17
Defined contribution plans	7	5
	$ 36	$ 22
Other post-retirement plans:		
Employer current service cost	$ 1	$ 1
Interest cost	4	3
Amortization of transitional obligation	1	1
Amortization of net actuarial losses	-	1
	$ 6	$ 6

The Company expects to contribute $72 million to its pension plans in 2009.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS *(unaudited)*

(millions of Canadian dollars, unless otherwise stated)

10. CAPITAL MANAGEMENT

The Company's capital management strategy is designed to maintain financial strength and flexibility to support profitable growth in all business environments. The Company continually monitors its capital management strategy and makes adjustments as appropriate. The Company's capital management strategy, objectives, evaluation measures, definitions and targets have not changed significantly from the prior period.

The Company is subject to certain financial covenants associated with its various banking and debt arrangements and was in compliance with all financial covenants for the three months ended March 31, 2009.

11. FINANCIAL RISKS AND FINANCIAL INSTRUMENTS

The Company is exposed to a number of financial risks in the normal course of its business operations, including market risks resulting from fluctuations in commodity prices, interest rates and foreign currency exchange rates, as well as credit risks and liquidity risks. The Company monitors its exposures to these risks and employs strategies to manage the risks as it considers appropriate. The Company's financial risk exposure and risk management strategies have not changed significantly from the prior period.

The fair values of the Company's financial assets and financial liabilities may fluctuate in response to these risks. Excluding debentures, senior notes and capital leases, which are recorded as long-term debt, the fair values of financial instruments equals or approximates their carrying amount, due to their short maturity. The fair value of debentures, senior notes and capital leases was $4,049 million at March 31, 2009 (December 31, 2008 – $3,868 million), compared with a carrying amount of $4,890 million at March 31, 2009 (December 31, 2008 – $4,749 million). The fair values of debentures, senior notes and capital leases are based on publicly quoted market values for instruments with similar terms and risks.

12. MERGER WITH SUNCOR ENERGY INC.

On March 23, 2009, the Company announced plans to merge with Suncor Energy Inc. These Consolidated Financial Statements do not reflect this proposed merger, which is still conditional on approval of Suncor and Petro-Canada shareholders, compliance with the Competition Act, and satisfaction of other customary approvals including regulatory, stock exchange, and the Court of Queen's Bench of Alberta approvals.