THIRD QUARTER 2010
Report to shareholders for the period ended September 30, 2010

Suncor Energy 2010 third quarter results

All financial figures are unaudited and in Canadian dollars unless noted otherwise. Certain financial measures referred to in this document are not prescribed by Canadian generally accepted accounting principles (GAAP). For a description of these measures, see Non-GAAP Financial Measures on page 43 of our report to shareholders for the period ended September 30, 2010. Certain crude oil and natural gas liquid volumes have been converted to millions of cubic feet equivalent of natural gas (mmcfe) on the basis of one barrel to six thousand cubic feet (mcf). Also, certain natural gas volumes have been converted to barrels of oil equivalent (boe) or thousands of boe (mboe) on the same basis. Mmcfe, boe and mboe may be misleading, particularly if used in isolation. A conversion ratio of one barrel of crude oil or natural gas liquids to six thousand cubic feet of natural gas is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent value equivalency at the wellhead.

On August 1, 2009, Suncor Energy Inc. completed its merger with Petro-Canada. As such, results for the three and nine month periods ended September 30, 2010 reflect results of post-merger Suncor and the comparative figures for the three month period ended September 30, 2009 reflect results for two months of the post-merger Suncor and one month of legacy Suncor, and for the nine month period ended September 30, 2009 reflect results for two months of the post-merger Suncor and seven months of legacy Suncor prior to the merger.

Suncor Energy Inc. recorded third quarter 2010 net earnings of $1.022 billion ($0.65 per common share), compared to net earnings of $929 million ($0.69 per common share) for the third quarter of 2009. Operating earnings[1] in the third quarter of 2010 were $654 million ($0.42 per common share), compared to $343 million ($0.25 per common share) in the third quarter of 2009.

The increase in operating earnings was primarily due to additional upstream production and higher benchmark prices in the third quarter of 2010 compared to the third quarter of 2009. Higher benchmark prices were partially offset by the widening of light/heavy crude differentials and the stronger Canadian dollar relative to the U.S. dollar.

Cash flow from operations[2] was $1.630 billion ($1.04 per common share) in the third quarter of 2010, compared to $574 million ($0.43 per common share) in the third quarter of 2009. The increase in cash flow from operations was primarily due to higher production volumes as well as higher realized prices.

Earnings
($ millions)

	2010 Q3	2009 Q3	**2010 YTD**	2009 YTD
Net earnings	**1 022**	929	**2 218**	689
Operating earnings[1]	**654**	343	**1 722**	755

Cash Flow from Operations[2]
($ millions)

2010 Q3	2009 Q3	**2010 YTD**	2009 YTD
1 630	574	**4 512**	1 670

Production[3]
(thousands of barrels of oil equivalent per day)

	2010 Q3	2009 Q3	**2010 YTD**	2009 YTD
Natural Gas and International and Offshore	**297.2**	201.7	**308.9**	91.7
Oil Sands (including Syncrude)	**338.3**	330.1	**302.9**	303.2
Total	**635.5**	531.8	**611.8**	394.9

Ratios
(per cent)
for the twelve months ended September 30

	2010	2009
Return on average shareholders' equity	**7.7**	2.7
Return on capital employed[4]	**7.9**	3.7

(1) Non-GAAP measure. See page 2 for a reconciliation of net earnings to operating earnings.
(2) Non-GAAP measure. See page 43.
(3) Includes Suncor's proportionate production share from the Syncrude joint venture.
(4) Non-GAAP measure. Excludes capitalized costs related to major projects in progress. See page 43.

Operating Earnings[1]

($ millions)	Three months ended September 30 2010	Three months ended September 30 2009	Nine months ended September 30 2010	Nine months ended September 30 2009
Net earnings from operations as reported	**1 022**	929	**2 218**	689
Change in fair value of commodity derivatives used for risk management[2]	**(28)**	(182)	**(185)**	544
Unrealized foreign exchange gain on U.S. dollar denominated long-term debt	**(220)**	(386)	**(120)**	(643)
Mark-to-market valuation of stock-based compensation	**45**	72	**(13)**	116
Project start-up costs	**18**	9	**39**	21
Costs related to deferral of growth projects	**28**	39	**82**	150
Merger and integration costs	**22**	51	**61**	67
Gain on disposals[3]	**(491)**	—	**(798)**	—
Impairment and write-offs[4]	**220**	—	**376**	—
Adjustments to provisions for assets acquired through the merger[5]	**38**	—	**62**	—
Impact of income tax rate adjustments on future income tax liabilities[6]	**—**	152	**—**	152
Gain on effective settlement of pre-existing contract with Petro-Canada[7]	**—**	(438)	**—**	(438)
Impact of recording acquired inventory at fair value[8]	**—**	97	**—**	97
Operating earnings from total operations[1]	**654**	343	**1 722**	755

(1) Operating earnings is a non-GAAP measure that adjusts net earnings for significant items that are not indicative of operating performance that management believes reduces the comparability of the underlying financial performance between periods. All reconciling items are presented on an after-tax basis.

(2) The company adjusts operating earnings for the change in fair value of significant crude oil risk management derivatives. The company also holds less significant risk management derivatives in other segments that are not adjusted for. Prior to the fourth quarter of 2009, the company had adjusted operating earnings for the change in fair value of all commodity derivatives, including those used for the purpose of earning energy trading revenues. The comparative periods have been restated to conform with current period presentation.

(3) Gains include sale of Natural Gas non-core assets, International and Offshore asset and share sales, unproven land sales and the sale of retail sites.

(4) Includes an impairment of natural gas properties due to the lower gas price environment and a write-down of book value based on expected sale price for International and Offshore assets. Year-to-date also includes a write-down related to certain extraction equipment in the Oil Sands segment and a write-down of land leases no longer being pursued by the Natural Gas segment.

(5) During the third quarter of 2010, some legacy Petro-Canada pipeline commitments were determined to be unfavorable as a result of certain Natural Gas asset dispositions. The year to date total includes adjustments for the unfavorable pipeline commitments, adjustments made to the cost estimates for the Exploration and Production Sharing Contract in Libya, a dry hole in Libya, write-off of unproven land in Natural Gas, and to the Montreal coker provision.

(6) Impact from an increase in the future income tax liability resulting from a revised provincial allocation for income tax purposes because of the merger with Petro-Canada.

(7) Impact from deemed settlement value assigned to bitumen processing contract with Petro-Canada upon close of the merger.

(8) Inventory acquired through the merger at fair value was sold during the third quarter of 2009, resulting in a one-time negative impact to earnings.

Suncor's total upstream production during the third quarter of 2010 averaged 635,500 boe per day, compared to 531,800 boe per day in the third quarter of 2009. Stronger operational performance in July and August in Oil Sands and throughout the quarter in International and Offshore and an additional month of incremental production from legacy Petro-Canada assets in 2010 contributed to the increase. This was offset by production impacts from planned and unplanned maintenance.

Oil Sands production (excluding proportionate production share from the Syncrude joint venture) contributed an average of 306,600 barrels per day (bpd) in the third quarter of 2010, compared to third quarter 2009 production of 305,300 bpd. Oil Sands production in July and August, 2010 averaged 322,000 bpd and 331,000 bpd, respectively, offset by September production, which averaged 264,000 bpd. Third quarter 2010 production was impacted by planned maintenance at one of two oil sands upgraders in September, which continued into October.

"This was one of our strongest quarters for oil sand production in Suncor's history," said Rick George, president and chief executive officer. "Reaching these volumes while also completing major planned maintenance demonstrates a solid foundation for reliable production going forward."

Cash operating costs for Suncor's oil sands operations (excluding Syncrude) were $33.60 per barrel in the third quarter of 2010, compared to $32.25 per barrel during the third quarter of 2009. The increase in cash operating costs per barrel was primarily due to the additional month of incremental costs from legacy Petro-Canada in situ assets offset by lower natural gas usage in the third quarter of 2010.

Suncor's proportionate production share from the Syncrude joint venture contributed an average of 31,700 bpd of production during the third quarter of 2010, compared to 24,800 bpd during the third quarter of 2009. The increase was primarily due to an additional month of production as a result of the merger.

Production from the Natural Gas business averaged 546 mmcfe per day in the third quarter of 2010, compared to 581 mmcfe per day during the third quarter of 2009, primarily due to decreased production volumes due to dispositions of non-core assets throughout 2010 partially offset by production added as a result of the merger.

Suncor's International and Offshore business contributed an average of 206,200 boe per day of production in the third quarter of 2010 compared to 104,900 boe per day during the third quarter of 2009. The increase was primarily due to an additional month of incremental production from legacy Petro-Canada assets in 2010, higher production at White Rose offshore East Coast Canada, and new production from the Ebla gas project in Syria, which was commissioned during the second quarter of 2010. This was partially offset by production quotas negatively affecting Libya production.

Results from the Refining and Marketing business also benefited from the additional month of post-merger activity. Total refined product sales averaged 88,900 cubic meters per day in the third quarter of 2010, compared to 69,900 cubic meters per day in the third quarter of 2009.

Strategy and Operational Update

In the company's oil sands operations, Suncor is continuing construction on its Firebag Stage 3 in situ oil sands expansion. The planned expansion is currently expected to achieve first oil production in the second quarter of 2011, with volumes ramping up over an estimated 18 to 24 month period towards planned production capacity of approximately 62,500 barrels of bitumen per day. Suncor is also progressing with work on Firebag Stage 4, which is expected to add an additional 62,500 barrels of bitumen per day of production capacity.

In Suncor's offshore East Coast Canada operations, development drilling in the North Amethyst portion of the White Rose Extensions continues with a total of 11 wells expected to be drilled through to late 2012. Development drilling for the first phase of the West White Rose development began in August, with first oil expected by early 2011. Primary production from the Hibernia South Extension project is expected in 2011.

Suncor continued with plans to divest of a number of non-core assets with the following milestones reached in the third quarter:

- On August 5, 2010, the company completed the previously announced sale of its Trinidad and Tobago assets, for net proceeds of US$378 million.
- On August 13, 2010, the company completed the previously announced sale of its shares in Petro-Canada Netherlands B.V., for net proceeds of €316 million.

- On August 31, 2010, the company completed the previously announced sale of its non-core natural gas properties located in west central Alberta, known as Bearberry and Ricinus, for net proceeds of $275 million.
- On September 8, 2010, the company reached an agreement to sell its non-core U.K. offshore assets for gross proceeds of £240 million. The sale is expected to close during the first quarter of 2011 and is subject to closing conditions, closing adjustments to the purchase price and regulatory and other approvals customary for transactions of this nature.
- On September 30, 2010, the company completed the previously announced sale of its non-core natural gas properties located in southern Alberta, known as Wildcat Hills, for net proceeds of $351 million.

To date, Suncor has disposed of, or reached agreements to dispose of, assets for aggregate consideration of approximately $3.5 billion prior to closing adjustments.

In September, Suncor marked an industry milestone, becoming the first oil sands company to complete surface reclamation of a tailings pond, a key step in returning the site back to nature. The 220-hectare site is located at Suncor's oil sands mining operations north of Fort McMurray. Known as Wapisiw Lookout, it was the company's first storage pond for oil sands tailings when commercial production began in 1967.

In Suncor's renewable energy operations, the St. Clair Ethanol Plant expansion project is expected to be completed on budget and on schedule in December 2010. The project is expected to double current production capacity, with the resulting ethanol blended fuels offsetting an additional 300,000 tonnes of carbon dioxide (CO_2) per year. Construction of the Wintering Hills wind power project is continuing with completion targeted by the end of 2011. The Wintering Hills project is expected to offset 200,000 tonnes of CO_2 per year.

"Wind energy and biofuels production are an important part of Suncor's overall strategy to lower the carbon intensity of our total energy portfolio," said George. "We believe investments in renewable energy sources, combined with ongoing investments to reduce the environmental impact of existing energy sources strikes the right balance for the economy and the environment."

In the third quarter, Suncor began to ramp up commercial implementation of a new tailings management technology – called TRO_{TM} – across its mining operations. Capital spending for large scale implementation of $TRO_{TM,}$ remains subject to Board of Director approval. The technology has the potential to reduce tailings reclamation time by decades and speed the return of oil sands mining sites to natural habitat.

Outlook

Suncor's outlook provides management's targets for 2010 in certain key areas of the company's business. Users of this forward-looking information are cautioned that actual results may vary materially from the targets disclosed. Readers are cautioned against placing undue reliance on this outlook.

The following operational outlook for 2010 has been revised from the operational outlook previously issued by management on July 29, 2010. The revisions are principally as follows:

- the realization on crude sales basket range has been adjusted to West Texas Intermediate (WTI) at Cushing less $9.75 to $10.75 per barrel from $7.00 to $8.00 per barrel as a result of a product mix more heavily weighted to sour synthetic crude and bitumen, resulting from the Oil Sands hydrotreater outage and disruptions to Enbridge pipeline service that limited export capacity of heavy crude products from Western Canada and negatively impacted both sour synthetic crude and bitumen price realizations;
- Oil Sands cash operating costs range of $38 to $42 per barrel has been adjusted to $38 to $40 primarily as a result of performance to date;
- the Natural Gas production outlook related to remaining targeted divestitures has been adjusted to nil from 140 mmcfe per day as a result of completed dispositions of the Ricinus/Bearberry/Wildcat Hills properties during the third quarter of 2010. While Natural Gas has completed its previously announced divestiture program and there are no further

divestments that will impact our 2010 production outlook, Natural Gas is considering additional divestitures, subject to board approval, as part of its strategic business alignment;

- the East Coast Canada production outlook has been adjusted to 70,000 bpd (+/−5%) from 65,000 bpd (+/−5%) primarily as a result of improved performance to date; and
- the International production outlook has been adjusted to 110,000 bpd (+/−5%) from 133,000 bpd (+/−5%) as a result of completed dispositions of our Trinidad and Tobago assets and shares of Petro-Canada Netherlands B.V. during the third quarter of 2010. The production outlook related to remaining targeted divestitures has been adjusted to 16,000 boe per day from 40,000 boe per day also due to the completed dispositions in the third quarter of 2010.

These changes to the operational outlook have a corresponding impact on the total production outlook which has been adjusted to 590,000 boe per day (+/−5%) from 610,000 boe per day (+/−5%) and total production related to remaining targeted divestitures, which has been adjusted to 16,000 boe per day from 63,000 boe per day.

	Nine Months Actual Ended September 30, 2010	2010 Full Year Outlook
Total production (boe per day) – before remaining targeted divestitures[1]	**611,800**	590,000 (+/−5%)
Total production (boe per day) – related to remaining targeted divestitures[1]	**N/A**	16,000
Oil Sands[2]		
Production (bpd)	**268,600**	280,000 (+/−5%)
Sales		
Diesel	**9%**	8%
Sweet	**30%**	32%
Sour	**48%**	50%
Bitumen	**13%**	10%
Realization on crude sales basket[3]	**WTI @ Cushing less Cdn$9.54 per barrel**	WTI @ Cushing less Cdn$9.75 to Cdn$10.75 per barrel
Cash operating costs[4]	**$39.70 per barrel**	$38 to $40 per barrel
Syncrude production (bpd)	**34,300**	36,000 (+/−5%)
Natural Gas		
Production (mmcfe per day) – before remaining targeted divestitures[5]	**621**	560 (+/−5%)
Production (mmcfe per day) – related to remaining planned targeted divestitures	**N/A**	N/A
Natural gas	**90%**	91%
Crude oil and liquids	**10%**	9%
East Coast Canada		
Production (bpd)	**70,400**	70,000 (+/−5%)
International		
Production (boe per day) – before remaining targeted divestitures[1]	**135,000**	110,000 (+/−5%)
Production (boe per day) – related to remaining planned targeted divestitures[1]	**N/A**	16,000
Crude oil and liquids	**82%**	87%
Natural gas	**18%**	13%

(1) Actual production results will be impacted by the timing of planned divestitures of assets.
(2) Excludes Suncor's proportionate production share from the Syncrude joint venture.
(3) Excludes the impact of hedging activities.
(4) Cash operating cost estimates (excluding Syncrude) are based on the following assumptions: (i) production volumes and sales mix as described in the table above; and (ii) an average natural gas price of $5.28 per mcf at AECO.
(5) The Natural Gas full year outlook is lower than our year to date actual production due to the previously mentioned asset divestitures in 2010.

This outlook is based on Suncor's current estimates, projections and assumptions for the 2010 fiscal year and is subject to change. Assumptions are based on management's experience and perception of historical trends, current conditions, anticipated future developments and other factors believed to be relevant. Assumptions for the Oil Sands 2010 full year outlook include reliability and operational efficiency initiatives which we expect to minimize further unplanned maintenance in 2010. Assumptions for the Natural Gas, East Coast Canada and International 2010 full year outlook include reservoir performance, drilling results, facility reliability, changes in production quotas and successful execution of planned maintenance turnarounds.

Risk Factors Affecting Performance

Factors that could potentially impact Suncor's operational outlook for 2010 include, but are not limited to:

- Bitumen supply. Ore grade quality, unplanned mine equipment and extraction plant maintenance, tailings storage and in situ reservoir performance could impact 2010 production targets.
- Performance of recently commissioned facilities. Production rates while new equipment is being lined out are difficult to predict and can be negatively impacted by unplanned maintenance.
- Unplanned maintenance. Production estimates could be negatively impacted if unplanned work is required at any of our mining, production, upgrading, refining, pipeline or offshore assets.
- Planned turnarounds. Production estimates could be negatively impacted if planned turnarounds are not effectively executed.
- Planned divestitures. Our inability to execute planned divestitures could impact our debt management and capital expenditure plans.
- Commodity prices. Significant declines in natural gas commodity prices could result in the shut-in of some of our natural gas production.
- Foreign operations. Suncor's foreign operations and related assets are subject to a number of political, economic and socio-economic risks. Suncor's operations in Libya may be constrained by production quotas.

The Strategy and Operational Update and Outlook above contain forward-looking information that is subject to a number of risks and uncertainties, many of which are beyond Suncor's control, including those outlined in Risk Factors Affecting Performance above. See the Legal Notice – Forward-Looking Information section of the MD&A included in our report to shareholders for the period ended September 30, 2010, for the material risks and assumptions underlying this forward looking information.

MANAGEMENT'S DISCUSSION AND ANALYSIS

November 2, 2010

This Management's Discussion and Analysis (MD&A) should be read in conjunction with Suncor's September 30, 2010 unaudited Interim Consolidated Financial Statements and the audited Consolidated Financial Statements and MD&A for the year ended December 31, 2009.

Non-GAAP Financial Measures

All financial information is reported in Canadian dollars (Cdn$) and in accordance with Canadian generally accepted accounting principles (GAAP), unless noted otherwise. Certain financial measures in this MD&A are not prescribed by GAAP and consist of operating earnings, cash flow from operations, return on capital employed (ROCE) and cash operating costs. Operating earnings are reconciled to GAAP net earnings in the Consolidated Operating Earnings Reconciliation and Segmented Earnings and Cash Flows section of this MD&A. Cash operating costs are included in the Oil Sands – Operating Expenses section of this MD&A. Cash flow from operations and ROCE are defined in the Non-GAAP Financial Measures section of this MD&A.

These non-GAAP financial measures do not have any standardized meaning and therefore are unlikely to be comparable to similar measures presented by other companies. These non-GAAP financial measures are included as management uses this information to analyze operating performance, leverage and liquidity. The additional information should not be considered in isolation or as a substitute for measures of performance prepared in accordance with Canadian GAAP.

Legal Advisory

This MD&A contains forward-looking information based on Suncor's current expectations, estimates, projections and assumptions. This information is subject to a number of risks and uncertainties, including those discussed in this MD&A and Suncor's other disclosure documents, many of which are beyond the company's control. Users of this information are cautioned that actual results may differ materially. Refer to the Legal Advisory – Forward-Looking Information section of this MD&A for information on material risk factors and assumptions underlying our forward-looking information.

On August 1, 2009, Suncor completed its merger with Petro-Canada, referred to in this MD&A as the "merger". For further information with respect to the merger, please refer to note 2 of the September 30, 2010 unaudited Interim Consolidated Financial Statements.

References to "we," "our," "Suncor," or "the company" mean Suncor Energy Inc., its subsidiaries, partnerships and joint venture investments, unless the context otherwise requires. References to "legacy Suncor" and "legacy Petro-Canada" refer to the applicable entity prior to the merger date.

The unaudited Interim Consolidated Financial statements include the results of post-merger Suncor from August 1, 2009. Amounts disclosed in this MD&A for the three month period ended September 30, 2009 reflect results for two months of the post-merger Suncor and one month of legacy Suncor, and for the nine month period ended September 30, 2009 reflect results for two months of the post-merger Suncor and seven months of legacy Suncor.

Certain amounts in prior years have been reclassified to conform to the current year's presentation.

Certain crude oil and natural gas liquid volumes have been converted to millions of cubic feet equivalent of natural gas (mmcfe) on the basis of one barrel to six thousand cubic feet (mcf). Also, certain natural gas volumes have been converted to barrels of oil equivalent (boe) or thousands of boe (mboe) on the same basis. Mmcfe, boe and mboe may be misleading, particularly if used in isolation. A conversion ratio of one barrel of crude oil or natural gas liquids to six thousand cubic feet of natural gas is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent value equivalency at the wellhead.

Additional information about Suncor and legacy Petro-Canada filed with Canadian securities commissions and the United States Securities and Exchange Commission (SEC), including periodic quarterly and annual reports and the Annual Information Form dated March 5, 2010 (the 2009 AIF), which is also filed with the SEC under cover of Form 40-F, is available on-line at www.sedar.com, www.sec.gov and our website www.suncor.com.

OVERVIEW AND HIGHLIGHTS OF CONSOLIDATED RESULTS

Description of the Business

Suncor is an integrated energy company headquartered in Calgary, Alberta. The company operates in four business segments: Oil Sands, Natural Gas, International and Offshore and Refining and Marketing. In addition, the company engages in third-party energy marketing and trading activities, and has investments in renewable energy opportunities, including Canada's largest ethanol plant by volume, as well as partnerships in four wind power projects, with a fifth project currently under construction.

As part of its ongoing strategic business alignment, Suncor is in the process of divesting a number of non-core assets in the Natural Gas and International and Offshore segments. Results, up to the closing date, of assets that have been sold during the quarter, as well as results from certain assets the company expects to sell are presented as discontinued operations, as determined in accordance with GAAP. As at September 30, 2010, Suncor has disposed of, or reached agreements to dispose of (subject to certain conditions), assets for aggregate consideration of approximately $3.5 billion, prior to closing adjustments, out of a targeted $2 to $4 billion. While Natural Gas has completed its previously announced divestitures, Natural Gas is considering additonal divestitures, subject to Board approval, as part of its strategic business alignment.

Highlights

- Consolidated total net earnings for the third quarter of 2010 were $1.022 billion, compared to net earnings of $929 million for the third quarter of 2009. Operating earnings in the third quarter of 2010 were $654 million, compared to $343 million in the third quarter of 2009. The increase in operating earnings was primarily due to additional upstream production, as a result of the merger, and higher benchmark prices in the third quarter of 2010 compared to the third quarter of 2009. Higher benchmark prices were partially offset due to the widening of heavy crude differentials and the stronger Canadian dollar relative to the U.S. dollar.
- As a result of disruptions to Enbridge pipeline service at the end of July and in early September, export capacity of heavy crude products from Western Canada was limited. As a result, the heavy crude differentials have widened and have resulted in lower sour crude and bitumen price realizations in the latter part of the third quarter and into the fourth quarter of 2010.
- Oil Sands experienced an unplanned outage at one of its hydrogen reformer units at the end of August 2010. This impacted the Oil Sands production mix, increasing the percentage of lower value sour crude product produced, but did not impact overall production volumes.
- Cash flow from operations was $1.630 billion in the third quarter of 2010, compared to $574 million in the third quarter of 2009. The increase in cash flow from operations was primarily due to increased operating earnings and an extra month of post-merger operating cash flow in the current quarter.
- Total upstream production in the current quarter was 635,500 boe per day (boe/d), compared to 531,800 boe/d in the third quarter of 2009. Stronger operational performance in July and August in Oil Sands and throughout the quarter in International and Offshore and higher production volumes as a result of the timing of the merger, contributed to the increase. This was offset by Oil Sands planned maintenance at Upgrader 2 and certain bitumen supply facilities.

- Total sales of refined petroleum products from the Refining and Marketing business averaged 88,900 cubic metres per day during the third quarter of 2010 compared to 69,900 cubic metres per day in the third quarter of 2009, reflecting additional sales volumes due to the timing of the merger.
- On August 5, 2010, the company completed the previously announced sale of its Trinidad and Tobago assets, for net proceeds of US$378 million.
- On August 13, 2010, the company completed the previously announced sale of its shares in Petro-Canada Netherlands B.V., for net proceeds of €316 million.
- On August 31, 2010, the company completed the previously announced sale of its non-core natural gas properties located in west central Alberta, known as Bearberry and Ricinus, for net proceeds of $275 million.
- On September 30, 2010, the company completed the previously announced sale of its non-core natural gas properties located in southern Alberta, known as Wildcat Hills, for net proceeds of $351 million.
- On September 8, 2010, the company reached an agreement to sell its non-core U.K. offshore assets for gross proceeds of £240 million. The sale is expected to close during the first quarter of 2011. The sale is subject to closing conditions, closing adjustments to the purchase price and regulatory and other approvals customary for transactions of this nature.
- Net debt at September 30, 2010 was $11.5 billion. Net debt decreased by $1.7 billion during the third quarter of 2010 largely due to proceeds on asset dispositions being used to pay down debt.
- During the quarter, Suncor marked an industry milestone by becoming the first oil sands company to complete surface reclamation of a tailings pond.

The above highlights contain forward-looking information. See the Legal Advisory – Forward-Looking Information section of this MD&A for the material risks and assumptions underlying this forward-looking information.

Quarterly Consolidated Financial Summary

Three months ended ($ millions, except as noted)	**Sept 30 2010**	June 30 2010	Mar 31 2010	Dec 31 2009	Sept 30 2009	June 30 2009	Mar 31 2009	Dec 31 2008
Revenues (net of royalties)								
Continuing operations	**8 636**	8 979	6 946	7 297	8 257	4 748	4 607	6 921
Discontinued operations (1)	**219**	220	343	363	195	20	26	31
	8 855	9 199	7 289	7 660	8 452	4 768	4 633	6 952
Net earnings (loss)								
Continuing operations	**609**	318	464	473	965	(46)	(189)	(216)
Discontinued operations	**413**	162	252	(16)	(36)	(5)	—	1
	1 022	480	716	457	929	(51)	(189)	(215)
Net earnings (loss) from continuing operations per common share								
Basic	**0.39**	0.20	0.30	0.30	0.72	(0.05)	(0.20)	(0.23)
Diluted	**0.39**	0.20	0.30	0.30	0.71	(0.05)	(0.20)	(0.23)
Net earnings (loss) per common share (2)								
Basic	**0.65**	0.31	0.46	0.29	0.69	(0.06)	(0.20)	(0.24)
Diluted	**0.65**	0.31	0.45	0.29	0.68	(0.06)	(0.20)	(0.24)
Operating earnings (loss) (2),(3)								
Continuing operations	**579**	728	203	339	379	43	380	13
Discontinued operations	**75**	53	84	(16)	(36)	(5)	—	1
	654	781	287	323	343	38	380	14
Operating earnings per common share (2),(3)	**0.42**	0.50	0.18	0.21	0.25	0.04	0.41	0.02
Cash flow from operations (2),(4)	**1 630**	1 758	1 124	1 129	574	295	801	231
Return on capital employed (twelve months ended) **(%) (4),(5)**	**7.9**	7.0	4.9	2.6	3.7	7.3	16.0	22.5

(1) Discontinued operations per Note 4 of the September 30, 2010 unaudited Interim Financial Statements excluding gain on disposal.

(2) Includes continuing and discontinued operations.

(3) Non-GAAP measure. See reconciliation on page 11 of this MD&A.

(4) Non-GAAP measure. See Non-GAAP Financial Measures section of this MD&A.

(5) Excludes capitalized costs related to major projects in progress.

Consolidated Operating Earnings Reconciliation[1]

($ millions)	Three months ended September 30 2010	Three months ended September 30 2009	Nine months ended September 30 2010	Nine months ended September 30 2009
Net earnings from continuing operations as reported	**609**	965	**1 391**	730
Change in fair value of commodity derivatives used for risk management[2]	**(28)**	(182)	**(185)**	544
Unrealized foreign exchange gain on U.S. dollar denominated long-term debt	**(220)**	(386)	**(120)**	(643)
Mark-to-market valuation of stock-based compensation	**45**	72	**(13)**	116
Project start-up costs	**18**	9	**39**	21
Costs related to deferral of growth projects	**28**	39	**82**	150
Merger and integration costs	**22**	51	**61**	67
Impact of income tax rate adjustments on future income tax liabilities[3]	**—**	152	**—**	152
Gain on disposals[4]	**(79)**	—	**(109)**	—
Impairment and write-offs[5]	**146**	—	**302**	—
Adjustments to provisions for assets acquired through the merger[6]	**38**	—	**62**	—
Gain on effective settlement of pre-existing contract with Petro-Canada[7]	**—**	(438)	**—**	(438)
Impact of recording acquired inventory at fair value[8]	**—**	97	**—**	97
Operating earnings from continuing operations	**579**	379	**1 510**	796
Net earnings (loss) from discontinued operations as reported	**413**	(36)	**827**	(41)
Gain on disposals of discontinued operations[4]	**(412)**	—	**(689)**	—
Impairment and write-offs of discontinued operations[5]	**74**	—	**74**	—
Operating earnings from total operations	**654**	343	**1 722**	755

(1) Operating earnings is a non-GAAP measure that adjusts net earnings for significant items that are not indicative of operating performance that management believes reduces the comparability of the underlying financial performance between periods. All reconciling items are presented on an after-tax basis.

(2) The company adjusts operating earnings for the change in fair value of significant crude oil risk management derivatives. The company also holds less significant risk management derivatives in other segments that are not adjusted for. Prior to the fourth quarter of 2009, the company had adjusted operating earnings for the change in fair value of all commodity derivatives, including those used for the purpose of earning energy trading revenues. The comparative periods have been restated to conform with current period presentation.

(3) Impact from an increase in the future income tax liability resulting from a revised provincial allocation for income tax purposes because of the merger.

(4) Continuing operations gain includes unproven Natural Gas land and Refining and Marketing sale of retail sites. Discontinued operations includes Natural Gas non-core asset sales and International and Offshore asset and share sales.

(5) Continuing operations includes an impairment of natural gas properties due to the lower gas price environment. Year-to-date results also include a write-down related to certain extraction equipment in the Oil Sands segment and a write-down of land leases no longer being pursued by the Natural Gas segment. Discontinued operations impairment includes a write-down of certain natural gas properties due to the lower gas price environment and assets from the International and Offshore segment that required a write-down of book value based on agreed sale price.

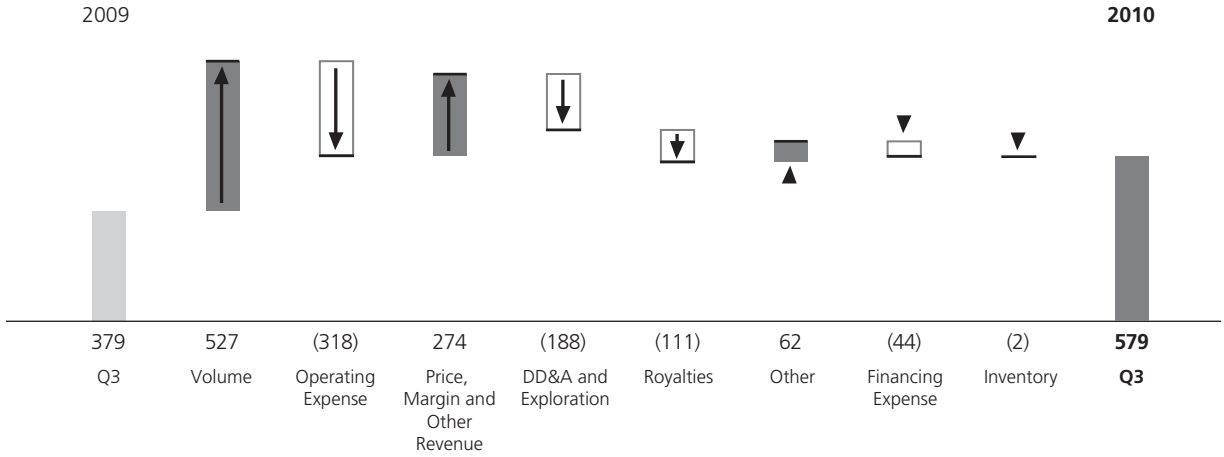
(6) During the third quarter of 2010, some legacy Petro-Canada pipeline commitments were determined to be unfavorable as a result of certain Natural Gas asset dispositions. The year to date total includes adjustments for the unfavorable pipeline commitments, adjustments made to the cost estimates for the Exploration and Production Sharing Contract in Libya, a dry hole in Libya, write-off of unproven land in Natural Gas, and to the Montreal coker provision.

(7) Impact from deemed settlement value assigned to bitumen processing contract with Petro-Canada upon close of the merger.

(8) Inventory acquired through the merger at fair value was sold during the third quarter of 2009, resulting in a one-time negative impact to earnings.

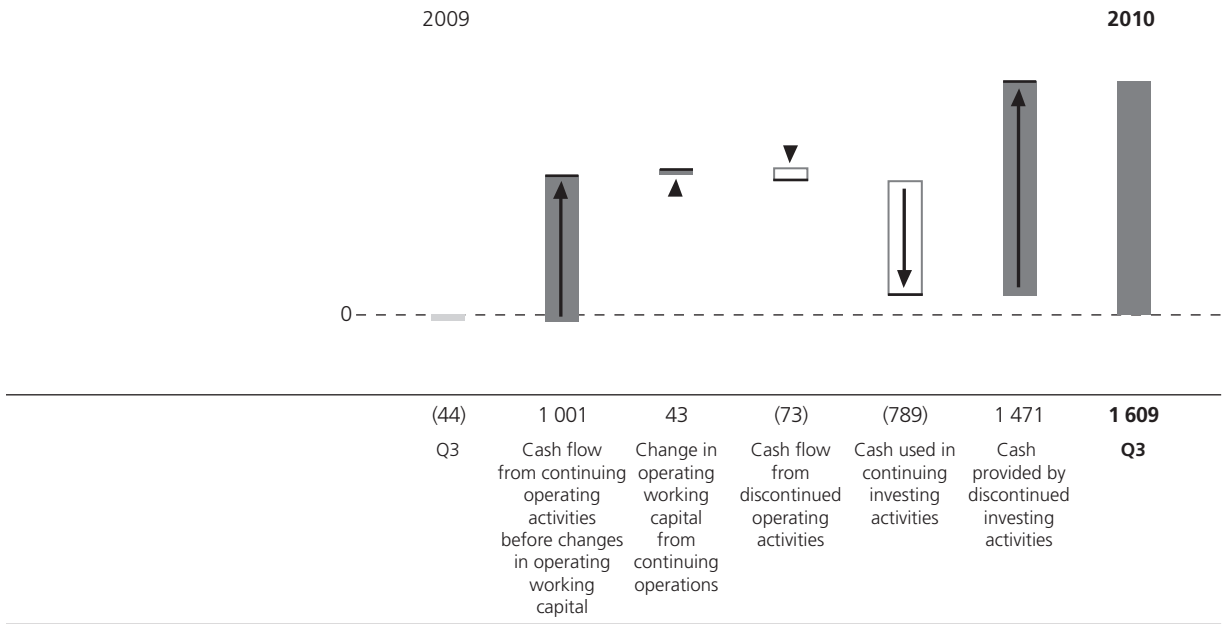
Consolidated Operating Earnings from Continuing Operations

($ millions)



Consolidated Net Cash Flow Before Financing Activities

($ millions)



Production Volumes

mboe per day (mboe/d)	Three months ended September 30 2010	2009	Nine months ended September 30 2010	2009
Continuing operations				
Oil Sands – Excluding Syncrude	**306.6**	305.3	**268.6**	294.8
Oil Sands – Syncrude	**31.7**	24.8	**34.3**	8.4
Natural Gas	**68.7**	60.5	**72.2**	36.8
International and Offshore	**176.8**	80.7	**171.2**	27.2
	583.8	471.3	**546.3**	367.2
Discontinued operations				
Natural Gas	**22.3**	36.3	**31.3**	19.5
International and Offshore	**29.4**	24.2	**34.2**	8.2
	51.7	60.5	**65.5**	27.7
Total	**635.5**	531.8	**611.8**	394.9

Commodity Prices – Benchmarks

Three months ended (average for the period)		Sept 30 2010	June 30 2010	Mar 31 2010	Dec 31 2009	Sept 30 2009	June 30 2009	Mar 31 2009	Dec 31 2008
West Texas Intermediate (WTI) crude oil at Cushing	US$/barrel	**76.20**	78.05	78.70	76.20	68.30	59.60	43.10	58.75
Dated Brent crude oil at Sullom Voe	US$/barrel	**76.85**	78.30	76.25	74.55	68.25	58.85	44.40	54.90
Dated Brent/Maya FOB price differential	US$/barrel	**9.35**	10.45	6.50	5.25	5.10	3.75	5.90	10.10
Canadian 0.3% par crude oil at Edmonton	Cdn$/barrel	**74.80**	76.30	80.45	77.00	70.60	65.30	50.10	64.65
Light/heavy crude oil differential of WTI at Cushing less Western Canadian Select at Hardisty	US$/barrel	**15.65**	14.05	8.95	12.10	10.10	7.50	8.95	19.30
Natural gas (Alberta spot) at AECO	Cdn$/mcf	**3.70**	3.85	5.35	4.25	3.00	3.65	5.65	6.80
New York Harbour 3-2-1 crack	US$/barrel	**9.60**	12.50	7.95	5.55	9.90	10.20	9.60	4.35
Chicago 3-2-1 crack	US$/barrel	**10.15**	11.05	5.65	4.15	7.65	10.15	8.95	5.25
Seattle 3-2-1 crack	US$/barrel	**16.60**	15.50	8.55	5.95	12.80	13.35	13.45	5.25
Gulf Coast 3-2-1 crack	US$/barrel	**7.45**	9.65	6.75	4.50	6.75	8.40	8.90	2.90
Exchange rate	US$/Cdn$	**0.96**	0.97	0.96	0.94	0.91	0.85	0.80	0.82

Earnings of Suncor depend largely on the operation and profitability of its upstream and downstream business segments. Benchmark commodity prices are one of the single biggest factors that affect the results of operations for Suncor on a company-wide and segment by segment basis.

Suncor's synthetic crude oil price realization is driven primarily by changes in price for WTI crude oil at Cushing. WTI prices for the three and nine months ended September 30, 2010 averaged US$76.20 and US$77.65 per barrel, respectively, compared with US$68.30 and US$57.00 per barrel, respectively, for the comparable periods in 2009. Suncor's bitumen trades at a differential to WTI at Cushing less Western Canadian Select at Hardisty. For the three and nine months ended September 30, 2010, this represented an average price discount of US$15.65 and US$12.88 per barrel to WTI, respectively, compared with US$10.10 and US$8.85 per barrel, respectively, for the comparable periods in 2009.

Suncor's natural gas production is primarily referenced to Alberta spot at AECO. Natural gas prices for the three and nine months ended September 30, 2010 averaged $3.70 and $4.30 per mcf, respectively, up from $3.00 and $4.10 per mcf, respectively, for the comparable periods in 2009.

The majority of Suncor's International and Offshore production is primarily referenced to Brent crude oil. Brent crude prices for the three and nine months ended September 30, 2010 averaged US$76.85 and US$77.13 per barrel, respectively, up from US$68.25 and US$57.17 per barrel, respectively, for the comparable periods in 2009.

The 3-2-1 crack spreads are industry indicators measuring the margin on a barrel of oil for gasoline and distillate. They are calculated by taking two times the gasoline margin at a certain location plus one times the distillate margin at the same location and dividing by three. Market crack spreads are based on quoted near-month contracts for WTI and spot prices for gasoline and diesel and do not necessarily reflect the actual crude purchase costs or product configuration of a specific refinery.

The majority of Suncor's revenues from the sale of oil and gas commodities receive prices that are determined by, or referenced to, U.S. dollar benchmark prices. The majority of Suncor's expenditures are realized in Canadian dollars. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of oil and gas commodities and correspondingly a decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of oil and gas commodities.

SEGMENTED EARNINGS AND CASH FLOWS

Oil Sands

	Three months ended September 30		Nine months ended September 30	
($ millions, unless otherwise noted)	**2010**	2009	**2010**	2009
Gross revenues and other income	**2 552**	2 615	**7 276**	4 918
Less: Royalties	**(290)**	(219)	**(542)**	(365)
Net revenues	**2 262**	2 396	**6 734**	4 553
Production (excluding Syncrude) (thousands of barrels per day – mbbls/d)	**306.6**	305.3	**268.6**	294.8
Syncrude production (mbbls/d)[1]	**31.7**	24.8	**34.3**	8.4
Average sales price (excluding Syncrude) ($/barrel)[2]	**67.53**	62.01	**69.05**	60.32
Net earnings	**412**	738	**1 005**	321
Operating earnings[3]	**440**	330	**1 088**	771
Cash flow from operations[3]	**779**	242	**1 974**	896
Cash operating costs (excluding Syncrude) ($/barrel)[3]	**33.60**	32.25	**39.70**	32.40
Sales mix (sweet/sour mix) (%)	**37/63**	44/56	**39/61**	47/53

(1) Production for the two month period, August and September 2009, was 37.4 mbbls/d.

(2) Before royalties and net of related transportation costs.

(3) Non-GAAP measure. Operating earnings and cash operating costs are reconciled below. Cash flow from operations is reconciled in the Non-GAAP Financial Measures section of this MD&A.

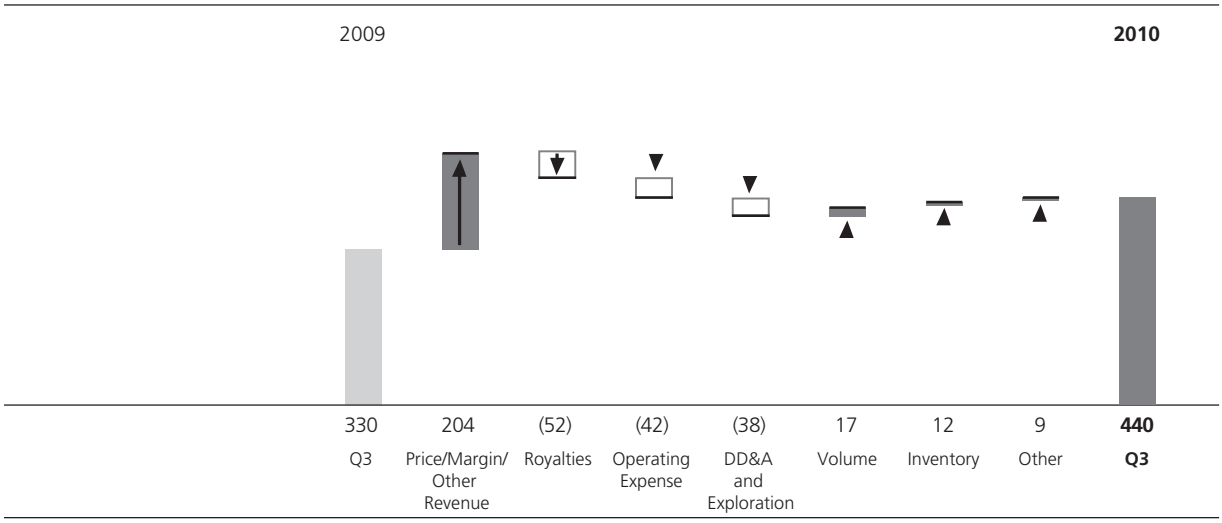
Operating Earnings Reconciliation

($ millions)	Three months ended September 30 2010	2009	Nine months ended September 30 2010	2009
Net earnings	**412**	738	**1 005**	321
Change in fair value of commodity derivatives used for risk management	**(28)**	(182)	**(185)**	544
Mark-to-market valuation of stock-based compensation	**11**	19	**7**	28
Project start-up costs	**17**	9	**36**	21
Costs related to deferral of growth projects	**28**	39	**82**	150
Impact of income tax rate adjustments on future income tax liabilities	**—**	140	**—**	140
Gain on effective settlement of pre-existing contract with Petro-Canada	**—**	(438)	**—**	(438)
Impact of recording acquired inventory at fair value	**—**	5	**—**	5
Losses on disposals	**—**	—	**2**	—
Impairment and write-offs	**—**	—	**141**	—
Operating earnings[1]	**440**	330	**1 088**	771

(1) Non-GAAP measure.

Operating Earnings from Continuing Operations

($ millions)



Oil Sands net earnings for the third quarter of 2010 were $412 million compared to $738 million for the third quarter of 2009. The higher net earnings in 2009 relative to the current period was primarily due to the impacts of a $438 million gain on a pre-existing processing fee agreement with Petro-Canada, partially offset by $140 million of increased income tax adjustments. Excluding the earning adjustments, operating earnings for the third quarter of 2010 were $440 million compared to $330 million for the third quarter of 2009.

Operating earnings were higher in the third quarter of 2010 compared to the third quarter of 2009 primarily due to stronger realized average prices for oil sands crude products and the receipt of fire-related insurance proceeds from Suncor's captive insurance company relating to the February 2010 upgrader fire. In addition, operating earnings in the third quarter of 2009 were negatively impacted by larger realized losses on commodity derivatives used for risk

management. These factors were partially offset by higher royalties and higher operating and depreciation expense in 2010. Although price realizations and production volumes were higher in the third quarter of 2010, results in the period were impacted by widened price differentials as a result of the Enbridge pipeline shut-down and maintenance at Upgrader 2 which affected both overall production volumes and product mix with a higher percentage of lower value sour crude being produced in the period. The maintenance at Upgrader 2 included both planned turnaround maintenance and unplanned maintenance due to a hydrogen plant outage.

Net earnings for the nine months ended September 30, 2010 were $1.005 billion, compared with $321 million in the first nine months of 2009. Net earnings in the first nine months of 2009 were negatively impacted by a large loss on commodity derivatives used for risk management, higher costs related to deferral of growth projects, and the same factors that impacted the third quarter of 2009 which included a gain on a pre-existing contract with Petro-Canada and income tax adjustments. This was partially offset by a $141 million write-down of assets, in the 2010 period, that were being used in the development of an alternative extraction process to crush and slurry oil sands at the mine face, which the company discontinued. Excluding the earning adjustments, operating earnings for the first nine months of 2010 were $1.088 billion, compared to $771 million in the same period of 2009.

Operating earnings were higher in the first nine months of 2010 compared to the first nine months of 2009 primarily due to stronger realized average prices for oil sands crude products and receipt of fire-related insurance proceeds from Suncor's captive insurance company. In addition, operating earnings were higher due to 2010 including nine months of Syncrude earnings compared to two months in the 2009 comparative. This was partially offset by the production impacts of the upgrader fires that occurred in the fourth quarter of 2009 and the first quarter of 2010, the spring turnarounds and the same factors that impacted third quarter production.

Cash flow from operations for the third quarter of 2010 was $779 million compared to $242 million in the third quarter of 2009. Cash flow from operations for the nine months ended September 30, 2010 was $1.974 billion compared to $896 million in the first nine months of 2009. The increase in cash flow from operations in 2010 from the comparable periods in 2009 was primarily due to higher 2009 current income tax settlements as a result of an accelerated tax payment due to the deemed year-end as a result of the merger, higher operating earnings and additional cash flow due to the timing of the merger.

Production Volumes

	Three months ended September 30		Nine months ended September 30	
(mbbls/d)	**2010**	2009	**2010**	2009
Production excluding Syncrude	**306.6**	305.3	**268.6**	294.8
Syncrude production [(1)]	**31.7**	24.8	**34.3**	8.4
Total production	**338.3**	330.1	**302.9**	303.2

(1) Production for the two month period, August and September 2009, was 37.4 mbbls/d.

(2) Apart from the Syncrude production, the merger did not result in increased Oil Sands production volumes. Production from MacKay River was included in Suncor's reported production during 2009 as volumes were processed by Suncor for a fee under a processing agreement. However, the addition of MacKay River has resulted in increased sales volumes for Oil Sands, as volumes processed for a fee under a processing agreement with legacy Petro-Canada were not included in sales prior to August 1, 2009.

Production, excluding Syncrude, in the third quarter of 2010 was comparable to the third quarter of 2009. In July and August of 2010 Oil Sands had strong operational performance and increased bitumen supply. September 2010 production was negatively impacted by planned turnaround maintenance at Upgrader 2 and bitumen supply facilities. Although not affecting overall production volumes, an outage in one of the hydrogen plants negatively impacted Oil Sands production

mix. Without the hydrogen unit in operation, the upgrader produced a higher percentage of lower value sour product. The third quarter of 2009 had stable production without offsetting major maintenance activities.

Syncrude production increased 28% in the third quarter of 2010, compared to the third quarter of 2009 primarily due to an additional month of production included in the 2010 comparatives as a result of the timing of the merger. This was partially offset by planned upgrader maintenance on a coker unit that began in September 2010.

For the nine months ended September 30, 2010, production, excluding Syncrude, was reduced due to the impact of the upgrader fires that occurred in the fourth quarter of 2009 and the first quarter of 2010, the turnarounds in the second quarter of 2010, and the same factors that impacted 2010 third quarter production. Syncrude production was higher for the nine months ended September 30, 2010 primarily due to the timing of the merger. The 2010 quarterly results included nine months of Syncrude production whereas the comparable 2009 period only included two months.

Prices

	Three months ended September 30		Nine months ended September 30	
(in Cdn $ per bbl)	**2010**	2009	**2010**	2009
Average sales price – excluding Syncrude	**67.53**	62.01	**69.05**	60.32
Average sales price – Syncrude	**78.83**	75.17	**79.79**	75.17
Sales mix (sweet/sour mix) (%)	**37/63**	44/56	**39/61**	47/53

Oil Sands benefited from higher benchmark crude oil prices in the quarter, which was partially offset by the stronger Canadian dollar relative to the U.S. dollar. In addition, heavy crude oil price differentials during the period widened as a result of the Enbridge pipeline disruptions that limited the export capacity of heavy crude products from Western Canada resulting in reduced demand and discounted sales. This negatively impacted both sour crude and bitumen price realizations in the latter part of the third quarter and into the fourth quarter of 2010.

In the third quarter of 2010, the Suncor average price realization on the crude sales basket, excluding hedging, was WTI less US$9.82 per bbl, or 87% of WTI, in comparison to the third quarter of 2009 where the Suncor average price realization on the crude sales basket, excluding hedging, was WTI less US$5.51 per bbl, or 92% of WTI. The sales mix during the third quarter of 2010 was negatively impacted by an unplanned outage in one of the hydrogen reformer units at Upgrader 2 which decreased the percentage of higher value sweet crude product produced and increased the volume of sour crude and bitumen sold in the market.

The average realized price for the first nine months of 2010 benefited from higher benchmark crude oil prices but was negatively affected by the widening of the heavy crude oil price differentials and the product mix issues noted in the third quarter of 2010 plus the impacts of the upgrader fires in the fourth quarter of 2009 and first quarter of 2010. The unplanned outage in one of the hydrogen units and the upgrader fires resulted in a decreased percentage of higher value sweet crude product being produced and increased the volume of sour crude and bitumen sold in the market, which negatively affected overall price realizations in the latter part of the third quarter and into the fourth quarter of 2010.

In the first nine months of 2010, the Suncor average price realization on the crude sales basket, excluding hedging, was WTI less US$9.20 per bbl, or 88% of WTI, in comparison to the first nine months of 2009 where the Suncor average price realization on the crude sales basket, excluding hedging, was WTI less US$4.03 per bbl, or 93% of WTI.

Inventory

In the third quarter of 2010 Oil Sands inventory build was smaller than the inventory build in the third quarter of 2009. The smaller inventory build in 2010 had a positive impact on earnings as the margin related to the inventory has now been recognized.

Operating Expenses

Operating expenses were higher in the third quarter of 2010, compared to the third quarter of 2009, primarily due to an additional month of operating costs from the MacKay River operation and the company's proportionate share of the Syncrude joint venture included in the third quarter of 2010 compared to the third quarter of 2009 due to the timing of the merger.

Third party crude and diesel product purchases were higher in the third quarter of 2010, compared to the third quarter of 2009, in order to facilitate placement of Oil Sands heavy production and to fulfill contractual obligations. Product purchases did not affect earnings as these are largely offset in revenue.

In the first nine months of 2010, operating expenses were higher compared to the first nine months of 2009. This was primarily due to the addition of nine months of operating costs from the MacKay River operations and the company's proportionate share of the Syncrude joint venture being included in the 2010 period, compared to only two months included in the 2009 period due to the timing of the merger.

During the third quarter of 2010, cash operating costs per bbl (excluding Syncrude) were $33.60 compared to $32.25 in the third quarter of 2009, an increase of 4% quarter over quarter. The increase in cash operating costs per barrel was primarily due to the additional month of incremental costs from MacKay River offset by lower natural gas usage in the third quarter of 2010.

For the first nine months of 2010, cash operating costs per bbl (excluding Syncrude) were $39.70 compared to $32.40 in the first nine months of 2009, an increase of 23% year over year. The nine month period increase in cash operating costs was primarily due to the additional seven months of operating costs from the MacKay River operation and reduced Oil Sands volumes as a result of planned and unplanned maintenance, including that related to the upgrader fires that occurred in the fourth quarter of 2009 and the first quarter of 2010.

Cash Operating Costs Reconciliation[1]

	Three months ended September 30				Nine months ended September 30			
	2010		2009		**2010**		2009	
	$ millions	$/barrel	$ millions	$/barrel	$ millions	$/barrel	$ millions	$/barrel
Operating, selling and general expenses[2]	**1 060**		981		**3 274**		2 977	
Add (Less) Natural gas costs, inventory changes, stock-based compensation, and other	**20**		(23)		**(186)**		(236)	
(Less) Safe mode costs	**(37)**		(45)		**(110)**		(260)	
(Less) Non-monetary transactions	**(12)**		(14)		**(45)**		(56)	
(Less) Syncrude-related operating, selling and general expenses	**(128)**		(66)		**(364)**		(66)	
Accretion of asset retirement obligations	**26**		27		**86**		80	
Cash costs	**929**	**32.95**	860	30.65	**2 655**	**36.20**	2 439	30.30
Natural gas	**17**	**0.60**	44	1.55	**184**	**2.50**	164	2.05
Imported bitumen (excluding other reported product purchases)	**2**	**0.05**	2	0.05	**73**	**1.00**	3	0.05
Cash operating costs	**948**	**33.60**	906	32.25	**2 912**	**39.70**	2 606	32.40

(1) Excludes Suncor's proportionate production share and operating costs from the Syncrude joint venture.

(2) GAAP measure.

Depreciation, Depletion and Amortization (DD&A)

The increase in DD&A expenses from the comparable periods in the prior quarter and prior year was due to newly commissioned assets and additional depreciation due to the assets acquired during the merger. Oil Sands assets are primarily depreciated over their useful life.

Royalties

In the third quarter of 2010 royalty expense was $290 million compared to $219 million in the third quarter of 2009. The increase was primarily due to higher royalty rates in 2010 compared to 2009, the receipt of insurance proceeds from Suncor's captive insurance company, for which royalties were payable, as well as the addition of the MacKay River volumes and Suncor's proportionate share of Syncrude production as a result of the merger. In situ projects continued in the pre-payout phase and royalties were calculated at the minimum royalty percentage of revenues, which was a rate based on the Canadian dollar equivalent of WTI up to a maximum of 9%.

During the first nine months of 2010, royalty expense increased to $542 million from $365 million in the first nine months of 2009 primarily due to the inclusion of a full nine months of royalties payable on production acquired during the merger (versus only two months in 2009), the higher royalty rates and receipt of insurance proceeds from Suncor's captive insurance company as described in the third quarter results.

The following table provides an estimation of royalties for Oil Sands operations (excluding Syncrude) in the years 2010 to 2013 under three price scenarios, and certain assumptions on which we have based our estimates for those price scenarios.

WTI Price/bbl US$	**60**	**80**	**100**
Natural gas (Alberta spot) Cdn$/mcf at AECO	4.30	4.55	5.05
Light/heavy crude oil differential of WTI at Cushing less Maya at the U.S. Gulf Coast US$	8.30	10.10	11.40
Differential of Maya at the U.S. Gulf Coast less Western Canadian Select at Hardisty US$	5.90	6.20	5.90
US$/Cdn$ exchange rate	0.90	1.00	1.00
Crown Royalty Expense (based on percentage of total Oil Sands gross revenue (excluding Syncrude))% (1)			
2010 (2)	4-6	7-9	7-9
2011-2013	4-6	8-10	11-13

(1) Reflects Crown's interim bitumen valuation methodology.

(2) For 2010, estimated royalty rates were based on actual year-to-date results plus forward months estimated as per assumptions.

The above table contains forward-looking information. See the Legal Advisory – Forward-Looking Information section of this MD&A for the material risks and assumptions underlying this forward-looking information.

Planned Maintenance Turnarounds

The six week planned turnaround for Upgrader 2 that began in September continued for three weeks into the fourth quarter of 2010. Incremental production impacts for the planned turnaround were combined with other assets that were also undergoing maintenance.

A coker turnaround, at Syncrude, also began in September and extended for three weeks into the fourth quarter of 2010.

Coker maintenance is scheduled for Upgrader 1 in the fourth quarter of 2010 and is expected to last for five weeks in total. Impacts from the maintenance are expected to be minimal as coker rates in Upgrader 2 will be increased to mitigate the outages at Upgrader 1.

Natural Gas

	Three months ended September 30		Nine months ended September 30	
($ millions, unless otherwise noted)	**2010**	2009	**2010**	2009
Gross revenues from continuing operations	**180**	122	**634**	248
Less: Royalties from continuing operations	**(19)**	(6)	**(58)**	(6)
Net revenues from continuing operations	**161**	116	**576**	242
Average sales price from continuing operations – natural gas ($/mcf)[1]	**3.66**	2.70	**4.24**	3.43
Average sales price from continuing operations – natural gas liquids and crude oil ($/barrel)[1]	**68.03**	58.31	**73.66**	51.89
Gross production				
Continuing operations (mmcfe per day – mmcfe/d)	**412**	363	**433**	221
Discontinued operations (mmcfe/d)	**134**	218	**188**	117
	546	581	**621**	338
Net earnings (loss)				
Continuing operations	**(167)**	(97)	**(212)**	(130)
Discontinued operations	**197**	(14)	**508**	(19)
	30	(111)	**296**	(149)
Operating earnings (loss)[2]				
Continuing operations	**(46)**	(79)	**(94)**	(112)
Discontinued operations	**14**	(14)	**48**	(19)
	(32)	(93)	**(46)**	(131)
Cash flow from operations[2]				
Continuing operations	**56**	39	**270**	107
Discontinued operations	**21**	35	**124**	62
	77	74	**394**	169

(1) Calculated before royalties and net of transportation costs.

(2) Non-GAAP measures. Operating earnings is reconciled below. Cash flow from operations is reconciled in the Non-GAAP Financial Measure section of the MD&A.

Operating Earnings Reconciliation

($ millions)	Three months ended September 30 2010	Three months ended September 30 2009	Nine months ended September 30 2010	Nine months ended September 30 2009
Net loss from continuing operations	**(167)**	(97)	**(212)**	(130)
Mark-to-market valuation of stock-based compensation	**4**	9	**(4)**	9
Gains on disposals	**(67)**	—	**(95)**	—
Impact of income tax rate adjustments on future income tax liabilities	**—**	9	**—**	9
Impairment and write-offs	**146**	—	**161**	—
Adjustments to provisions for assets acquired through the merger	**38**	—	**56**	—
Operating loss from continuing operations[1]	**(46)**	(79)	**(94)**	(112)
Net earnings (loss) from discontinued operations	**197**	(14)	**508**	(19)
Gains on disposals of discontinued operations	**(205)**	—	**(482)**	—
Impairment and write-offs	**22**	—	**22**	—
Operating loss from total operations[1]	**(32)**	(93)	**(46)**	(131)

(1) Non-GAAP measure.

Natural Gas had total net earnings of $30 million in the third quarter of 2010, compared with a net loss of $111 million in the third quarter of 2009. Net earnings in the third quarter of 2010 included a $272 million gain on asset dispositions consisting of $205 million related to discontinued operations for non-core assets sold and $67 million related to the sale of unproven land. These gains were partially offset by a write-down of certain assets where the divestment of lower-cost properties resulted in the carrying value of a remaining area being greater than its expected discounted future cash flows. Expenses also included the recognition of unfavourable legacy Petro-Canada pipeline commitments resulting from the asset dispositions. Excluding the earning adjustments, total operating loss for the third quarter of 2010 was $32 million compared to an operating loss of $93 million in the third quarter of 2009.

The decrease in total operating loss in the third quarter of 2010 was primarily due to higher benchmark commodity prices and lower exploration expenses when compared to the third quarter of 2009. This was partially offset by decreased production volumes due to dispositions of non-core assets throughout 2010.

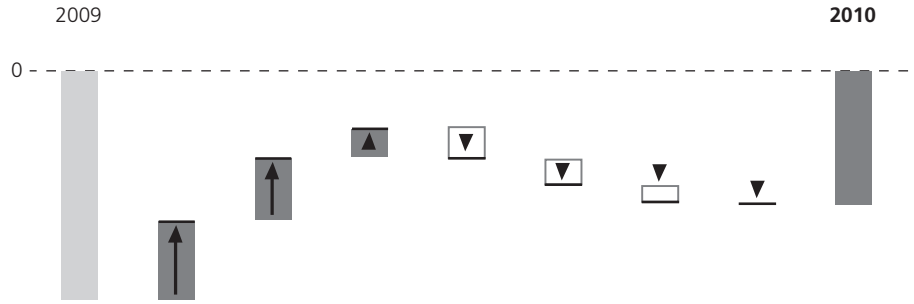
Net earnings for the first nine months of 2010 were $296 million, compared to a net loss of $149 million in the first nine months of 2009. Net earnings for the first nine months of 2010 were impacted by the same factors that impacted the third quarter of 2010 with additional gains booked on the sale of non-core assets. These factors were partially offset by expenses related to the write-down of certain land leases in Western Canada and Alaska that the company was no longer pursuing as part of its strategic business alignment. Excluding the earning adjustments, total operating loss for the first nine months of 2010 was $46 million, compared to an operating loss of $131 million in the same period of 2009.

The year-to-date decrease in operating loss was primarily due to higher benchmark commodity prices, higher production volumes due to assets acquired as a result of the merger, and lower exploration expenses when compared to the first nine months of 2009.

Continuing Operations

Operating Loss from Continuing Operations

($ millions)



(79)	27	22	10	(10)	(9)	(6)	(1)	**(46)**
Q3	Price	DD&A and Exploration	Volume	Operating Expenses	Royalties	Other	Financing Expense	**Q3**

Operating loss from continuing operations was $46 million in the third quarter of 2010, compared to an operating loss from continuing operations of $79 million in the third quarter of 2009. The decreased operating loss from continuing operations was due to the same factors that impacted total operating loss except that there was an increase in production volumes due to having only two months of post-merger Suncor volumes in the third quarter of 2009. Cash flow from continuing operations for the third quarter of 2010 was $56 million, compared to $39 million in the third quarter of 2009. The increased cash flow from continuing operations was due primarily to the same factors that impacted operating earnings, excluding the impact of the non-cash exploration expenses.

Operating loss from continuing operations for the first nine months of 2010 was $94 million, compared to an operating loss from continuing operations of $112 million in the first nine months of 2009. Cash flow from continuing operations for the first nine months of 2010 increased to $270 million from $107 million in the first nine months of 2009. The year-to-date decrease in continuing operating losses as well as the increase in cash flow from continuing operations was due to higher benchmark commodity prices, higher production volumes due to assets acquired as a result of the merger and lower exploration expenses when compared to the first nine months of 2009.

Production Volumes

	Three months ended September 30		Nine months ended September 30	
(mmcfe/d)	**2010**	2009	**2010**	2009
Natural gas from continuing operations	**380**	335	**399**	207
Natural gas liquids and crude oil from continuing operations	**32**	28	**34**	14
Gross production from continuing operations	**412**	363	**433**	221

Continuing operations gross production increased 13% in the third quarter of 2010, compared to the third quarter of 2009. The increase primarily reflects additional production associated with the assets acquired as a result of the merger.

Gross production from continuing operations increased 96% in the first nine months of 2010, compared to the first nine months of 2009. The increase primarily reflects assets acquired as a result of the merger, partially offset by natural production declines.

Prices

Natural gas benefited from higher benchmark natural gas and crude oil prices in the quarter and the first nine months of 2010 versus the comparable periods in 2009.

Operating Expenses

Operating expenses from continuing operations increased in the third quarter of 2010, compared to the third quarter of 2009, primarily as a result of turnaround activity in the third quarter of 2010 and higher continuing operations production compared to the third quarter of 2009 as a result of the merger.

Operating expenses from continuing operations increased in the first nine months of 2010 compared to the first nine months of 2009 due to the operating expenses associated with the assets acquired as a result of the merger being included for the full nine months of 2010 compared to only two months in the first nine months of 2009 due to the timing of the merger.

DD&A and Exploration Expenses

DD&A from continuing operations increased in the third quarter of 2010 compared to the same period in 2009 primarily due to higher production volumes from assets acquired as a result of the merger. DD&A is primarily based on units of production.

Exploration expenses from continuing operations decreased in the third quarter of 2010 compared to the same period in 2009. In the 2010 period there were no dry hole costs, as a result of decreased drilling activity, compared to dry hole costs in the third quarter of 2009.

DD&A expenses from continuing operations increased in the first nine months of 2010 compared to the same period in 2009 primarily due to the increase in capital assets and production as a result of the merger.

Exploration expenses from continuing operations decreased in the first nine months of 2010 compared to the same period in 2009 primarily due to the reduction in dry hole costs in 2010.

Royalties

In the third quarter of 2010, total Crown royalties from continuing operations increased to $19 million, from $6 million in the third quarter of 2009. The increased royalties were primarily associated with the production acquired as a result of the merger, and higher natural gas prices in 2010 versus the comparative period in 2009.

Total royalties from continuing operations increased to $58 million in the first nine months of 2010, from $6 million in the first nine months of 2009. The increase was primarily due to royalty credits received in 2009.

Discontinued Operations

Discontinued operations as determined in accordance with GAAP, include the results, up to the closing date, of assets that have been sold during the quarter, as well as the results from certain assets the company expects to sell. Comparative results have been restated to reflect the impact of operations that have been classified as discontinued during the third quarter of 2010.

During the third quarter of 2010, Natural Gas continued its progress on strategic divestment activities:

- On August 31, 2010, the company sold non-core natural gas properties located in west central Alberta, known as Bearberry and Ricinus, for net proceeds of $275 million with an effective date of April 1, 2010.
- On September 30, 2010, the company sold non-core natural gas properties located in southern Alberta, known as Wildcat Hills, for net proceeds of $351 million with an effective date of May 1, 2010.

International and Offshore

	Three months ended September 30 [1]		Nine months ended September 30 [1]	
($ millions, unless otherwise noted)	**2010**	2009	**2010**	2009
Gross revenues from continuing operations	**1 236**	571	**3 750**	571
Less: Royalties	**(278)**	(215)	**(928)**	(215)
Net revenues from continuing operations	**958**	356	**2 822**	356
Production from continuing operations (mboe/d)				
East Coast Canada	**66.3**	32.9	**70.4**	11.1
U.K. (Buzzard)	**58.6**	19.5	**55.5**	6.6
Libya	**35.4**	28.3	**35.4**	9.5
Syria	**16.5**	—	**9.9**	—
Production from discontinued operations (mboe/d)	**29.4**	24.2	**34.2**	8.2
Total production (mboe/d)	**206.2**	104.9	**205.4**	35.4
Average sales price from continuing operations [2]				
East Coast Canada ($/bbl)	**78.78**	75.22	**78.11**	75.22
U.K. (Buzzard) ($/boe)	**75.60**	72.02	**75.35**	72.02
Other International ($/boe)	**74.90**	75.60	**76.16**	75.60
Net earnings (loss)				
Continuing operations	**236**	93	**662**	93
Discontinued operations	**216**	(22)	**319**	(22)
	452	71	**981**	71
Operating earnings[3]				
Continuing operations	**242**	125	**693**	125
Discontinued operations	**61**	(22)	**164**	(22)
	303	103	**857**	103
Cash flow from operations[3]				
Continuing operations	**568**	238	**1 627**	238
Discontinued operations	**124**	55	**354**	55
	692	293	**1 981**	293

(1) Three months ended September 30, 2009 and nine months ended September 30, 2009 reflects two months of post-merger Suncor. Total production for the two month period, August and September 2009, was 158.2 mboe/d.

(2) Calculated before royalties and net of transportation costs.

(3) Non-GAAP measure, operations earnings is reconciled below. Cash flow from operations is reconciled in the Non-GAAP Financial Measures section of the MD&A.

Operating Earnings Reconciliation

($ millions)	Three months ended September 30 2010	2009	Nine months ended September 30 2010	2009
Net earnings from continuing operations	**236**	93	**662**	93
Mark-to-market valuation of stock-based compensation	**5**	7	**—**	7
Project start-up costs	**1**	—	**3**	—
Impact of recording acquired inventory at fair value	**—**	25	**—**	25
Adjustments to provisions for assets acquired through the merger	**—**	—	**28**	—
Operating earnings from continuing operations[1]	**242**	125	**693**	125
Net earnings (loss) from discontinued operations	**216**	(22)	**319**	(22)
Gains on disposals of discontinued operations	**(207)**	—	**(207)**	—
Impairment and write-offs	**52**	—	**52**	—
Operating earnings from total operations[1]	**303**	103	**857**	103

(1) Non-GAAP measure.

Suncor has continuing operations in the U.K. (Buzzard), Norway (exploration), Libya, Syria and East Coast Canada. Discontinued operations include certain U.K. sections of the North Sea and results from the Netherlands and Trinidad and Tobago up until the closing date of their sales which was August 13 and August 5, 2010 respectively.

International and Offshore had total net earnings of $452 million in the third quarter of 2010, compared to $71 million in the third quarter of 2009. Net earnings in the third quarter of 2010 included a $207 million gain on asset dispositions offset by a $52 million write-down of U.K. assets to reflect the agreed upon sale price of the assets. In the third quarter of 2009 net earnings included a negative impact of recording acquired inventory at fair value. Excluding the earning adjustments, total operating earnings for the third quarter of 2010 were $303 million, compared to $103 million for the same period in 2009.

The increase in total operating earnings in the third quarter of 2010 was primarily due to the three months of operations included in the third quarter of 2010 compared to only two months in the third quarter of 2009 due to the timing of the merger. Production coming on-stream at North Amethyst (East Coast Canada) and Syria and higher benchmark prices all contributed to the increase. This was partially offset by increased DD&A and royalty expenses and ongoing production quota constraints in Libya.

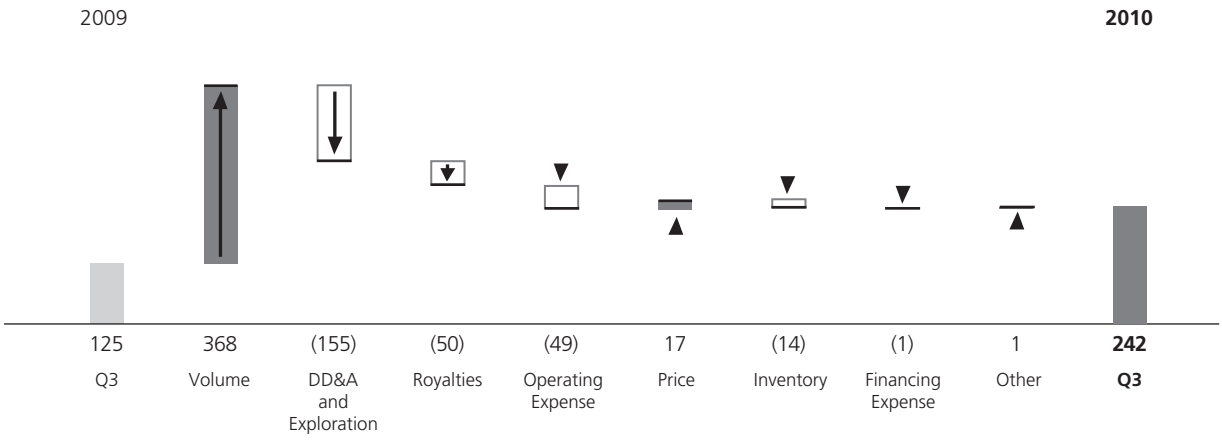
Net earnings for the first nine months of 2010 were $981 million compared to $71 million in the first nine months of 2009. The first nine months of net earnings in 2010 were a result of the same factors that impacted the third quarter of 2010 with the addition of $19 million related to past cost adjustments for the Exploration and Production Sharing Contract in Libya and $9 million due to a dry hole in Libya. Due to the timing of the merger, the first nine month of 2009 only includes two months of earnings.

Total operating earnings in the first nine months of 2010 were $857 million compared to $103 million in the first nine months of 2009. Operating earnings in the first nine months of 2010 were positively impacted due to 2010 including nine months of operations compared to the inclusion of only two months in 2009 due to the timing of the merger, higher commodity prices and overall strong production results. This was partially offset by ongoing production quota constraints in Libya and three week maintenance turnarounds at Buzzard and Terra Nova.

Continuing Operations

Operating Earnings from Continuing Operations

($ millions)



Operating earnings from continuing operations were $242 million in the third quarter of 2010, compared to operating earnings from continuing operations of $125 million in the third quarter of 2009. The increased operating earnings from continuing operations was due to the same factors that impacted total operating earnings. Cash flow from continuing operations in the third quarter of 2010 was $568 million, compared to $238 million in the third quarter of 2009. The increased cash flow from continuing operations was due to 2010 including three months of operations compared to the inclusion of only two months in 2009 due to the timing of the merger.

Operating earnings from continuing operations were $693 million for the first nine months of 2010 as compared to $125 million for the same period in 2009. Cash flow from continuing operations was $1.627 billion for the first nine months of 2010 compared to $238 million for the same period in 2009. The first nine months of 2010 results were primarily impacted due to 2010 including nine months of operations compared to the inclusion of only two months in 2009 due to the timing of the merger.

Volumes

	Three months ended September 30		Nine months ended September 30	
(mboe/d)	**2010**	2009	**2010**	2009
Production from continuing operations				
East Coast Canada				
Terra Nova	**17.2**	10.6	**24.6**	3.6
Hibernia	**32.3**	18.9	**30.9**	6.4
White Rose	**16.8**	3.4	**14.9**	1.1
U.K.				
Buzzard	**58.6**	19.5	**55.5**	6.6
Libya	**35.4**	28.3	**35.4**	9.5
Syria	**16.5**	—	**9.9**	—
Production from discontinued operations	**29.4**	24.2	**34.2**	8.2
Total production	**206.2**	104.9	**205.4**	35.4

Overall, production was higher in the third quarter of 2010 compared to the third quarter of 2009 primarily due to the additional month of production included in the 2010 comparatives as a result of the timing of the merger. In addition to the timing of the merger, East Coast Canada recorded higher production at White Rose with North Amethyst coming on-stream in the second quarter of 2010, higher Buzzard production in the third quarter of 2010 due to the absence of turnaround activity compared to the third quarter of 2009 and Syria production came on-stream in the second quarter of 2010. This was partially offset by ongoing production quota constraints in Libya.

Production in the first nine months of 2010 was significantly higher than the first nine months of 2009 primarily due to the timing of the merger. The 2010 results include nine months of production whereas the comparable 2009 period included two months. The increase in the first nine months of 2010 compared to the first nine months of 2009 was also due to higher production at White Rose with North Amethyst coming on-stream and Syria production coming on-stream in the second quarter of 2010. Buzzard also had higher production in the third quarter of 2010 due to the absence of turnaround activity compared to the third quarter of 2009.

Prices

International and Offshore benefited from higher price realizations in the third quarter and for the first nine months of 2010 due to higher benchmark commodity prices, relative to the comparable periods in 2009.

Inventory

In the third quarter of 2010 International and Offshore inventory build was larger than the inventory build in the third quarter of 2009. The larger inventory build in 2010 had a negative impact on earnings as the margins cannot be recognized until sold.

Operating Expenses

Operating expenses from continuing operations increased in the third quarter of 2010 compared to the third quarter of 2009 primarily due to the additional month of production included in the 2010 comparatives as a result of the merger and costs associated with the new production delivered from Syria and White Rose.

Operating expenses from continuing operations increased in the first nine months of 2010, compared to the first nine months of 2009, primarily due to the timing of the merger.

DD&A

DD&A expenses from continuing operations were higher in the third quarter of 2010 and the first nine months of 2010, compared to the similar 2009 periods. The increase was primarily due to the timing of the merger, the additional assets acquired as a result of the merger and new production coming on-stream in 2010.

Royalties

Total royalties in the International and Offshore segment during the third quarter of 2010 were $278 million from continuing operations, compared to $215 million in the third quarter of 2009. In the first nine months of 2010, royalties in the International and Offshore segment were $928 million, compared to $215 million in the first nine months of 2009 as a result of the timing of the merger.

Royalties were higher in the third quarter of 2010, compared to the third quarter of 2009, primarily due to higher volumes as a result of the production from assets acquired from the merger and higher prices which was partially offset by increased capital and operating expenditures for East Coast Canada operations. Royalty expenses were higher in Syria due

to production commencing in the second quarter of 2010 partially offset by a decrease in royalty expense in Libya. Royalties are not paid on U.K. assets.

International royalties are determined in accordance with production sharing agreements in Libya and Syria. The royalty amounts calculated reflect the difference between Suncor's working interest in the particular project and the net revenue attributable to Suncor under the terms of the contract. All government interest in the operations, except for income taxes, are considered royalty obligations.

The following table provides an estimation of royalties related to Suncor's East Coast Canada assets for 2010 to 2013 for three price scenarios.

WTI Price/bbl US$	**60**	80	100
US$ / Cdn$ exchange rate	0.90	1.00	1.00
Crown Royalty Expense (based on percentage of gross revenue)%			
2010 – Crude[(1)]	32-34	32-34	32-34
2011-2013	22-26	23-27	25-29

(1) For 2010, estimated royalty rates are based on actual year-to-date results plus forward months estimated as per assumptions.

The above table contains forward-looking information. See the Legal Advisory – Forward Looking Information section of this MD&A for the material risks and assumptions underlying this forward-looking information.

Planned Maintenance Turnarounds

There is a three week turnaround scheduled for White Rose in the fourth quarter of 2010. In addition, Buzzard in the North Sea began hook-up and commissioning of the sulphur handling platform in October.

Discontinued Operations

Discontinued operations, determined in accordance with GAAP, include the results, up to the closing date, of assets that have been sold during the quarter, as well as results from certain assets the company expects to sell. Comparative results have been restated to reflect the impact of operations that have been classified as discontinued during the third quarter of 2010.

During the third quarter of 2010, International and Offshore continued its progress on strategic divestiture activities:

- On August 5, 2010, the company completed the sale of its assets in Trinidad and Tobago, for net proceeds of US$378 million with an effective date of January 1, 2010.
- On August 13, 2010, the company sold its shares in Petro-Canada Netherlands B.V., for net proceeds of €316 million with an effective date of January 1, 2010.
- On September 8, 2010, the company reached an agreement to sell certain of its non-core U.K. offshore assets for gross proceeds of £240 million. The sale involves Petro-Canada UK Limited interests in 12 offshore production and exploration licenses in the U.K. sector of the North Sea. The sale is expected to close during the first quarter of 2011, with an effective date of July 1, 2010 and is subject to closing conditions, closing adjustments to the purchase price and regulatory and other approvals customary for transactions of this nature. See the Legal Advisory – Forward-Looking Information section of this MD&A for the material risks and assumptions underlying this forward-looking information relating to the sale of the U.K. assets.

Refining and Marketing

($ millions, unless otherwise noted)	Three months ended September 30 2010	2009	Nine months ended September 30 2010	2009
Revenues	**5 194**	3 852	**15 236**	7 108
Refined Product Sales (thousands of cubic metres per day – m^3/d)				
Gasoline	**42.4**	34.4	**41.1**	22.8
Distillates	**29.1**	22.1	**29.1**	14.4
Other, including petrochemicals	**17.4**	13.4	**16.6**	8.0
Total refined product sales	**88.9**	69.9	**86.8**	45.2
Crude oil processed by Suncor (thousands of m^3/d)	**67.3**	53.3	**64.8**	35.5
Total Net Earnings	**152**	45	**429**	256
Operating earnings[1]	**149**	126	**393**	338
Cash flow from operations[1]	**326**	264	**917**	663

(1) Non-GAAP measure. Operating earnings is reconciled below. Cash flow operations is reconciled in the Non-GAAP Financial Measures section of this MD&A.

Operating Earnings Reconciliation

($ millions)	Three months ended September 30 2010	2009	Nine months ended September 30 2010	2009
Net earnings	**152**	45	**429**	256
Mark-to-market valuation of stock-based compensation	**9**	14	**2**	15
Impact of recording acquired inventory at fair value	**—**	67	**—**	67
Gains on disposals	**(12)**	—	**(16)**	—
Adjustments to provisions for assets acquired through the merger	**—**	—	**(22)**	—
Operating earnings[1]	**149**	126	**393**	338

(1) Non-GAAP measure.

The Refining and Marketing business recorded net earnings of $152 million in the third quarter of 2010, compared with $45 million in the third quarter of 2009. The lower net earnings in 2009 relative to the current period was primarily due to a $67 million negative impact to earnings as a result of inventory acquired through the merger at fair value. In the third quarter of 2010, net earnings included a gain of $12 million related to planned retail site divestments. Excluding the earnings adjustments, operating earnings for the third quarter of 2010 were $149 million compared to operating earnings of $126 million in the third quarter of 2009.

Refining and product supply activities, which includes retail, wholesale and the rack forward portion of lubricants, contributed net earnings of $76 million in the third quarter of 2010, up from net earnings of $25 million in the third quarter of 2009. Results were positively impacted by the fact that the 2009 comparative period was only comprised of two months of post merger results as compared to the three months included in the 2010 period. Other positive contributions to net earnings included wider light/heavy and light/sour synthetic crude pricing differentials and stronger distillate cracking margins. These were partially offset by lower utilization at the Sarnia refinery due to the disruptions to Enbridge pipeline services, which impacted feedstock, weaker gasoline cracking margins and generally weaker crack to rack margins for both gasoline and distillate.

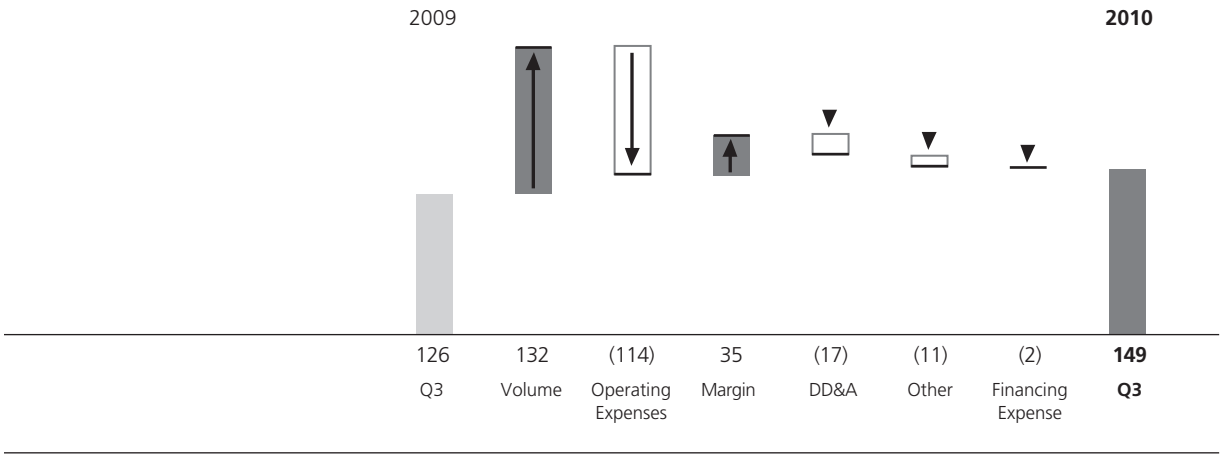
Marketing activities, which includes retail, wholesale and the rack forward portion of lubricants, contributed net earnings of $76 million in the third quarter of 2010, compared with $20 million in the third quarter of 2009. Higher marketing results reflected higher sales volumes due to the timing of the merger though retail and wholesale margins were weaker.

Net earnings for the first nine months of 2010 were $429 million, compared to $256 million in the first nine months of 2009. In addition to the same factors that impacted net earnings in the third quarter, the nine month period ended September 30, 2010 included a $22 million benefit related to the reduction of the Montreal Coker Project shut-down and decommissioning provision. Excluding the earnings adjustments total operating earnings for the nine month period ended September 30, 2010 were $393 million, compared to operating earnings of $338 million in the same period of 2009.

Cash flow from operations was $326 million in the third quarter of 2010, compared to $264 million in the same period of 2009. The increase was a result of the same factors that affected third quarter operating earnings. Cash flow from operations for the first nine months of 2010 increased to $917 million from $663 million in the first nine months of 2009. The year-to-date change in cash flow from operations was primarily due to the same factors that affected third quarter operating earnings and cash flow from operations.

Operating Earnings from Continuing Operations

($ millions)



Operating earnings for the third quarter of 2010 increased by $23 million over the same period in 2009 primarily due to increased volumes from the additional month of merged operations included in the third quarter of 2010, and improved margins, compared to the third quarter of 2009. This was partially offset by higher operating expenses.

The increase in operating earnings for the first nine months of 2010 over the same period in 2009 was primarily due to the same factors that impacted third quarter operating earnings.

Volumes

(thousands of m^3/d)	Three months ended September 30 2010	Three months ended September 30 2009	Nine months ended September 30 2010	Nine months ended September 30 2009
Refined Product Sales				
Gasoline				
Eastern North America	**22.5**	18.3	**22.0**	11.7
Western North America	**19.9**	16.1	**19.1**	11.1
	42.4	34.4	**41.1**	22.8
Distillates				
Eastern North America	**11.7**	10.3	**12.2**	7.0
Western North America	**17.4**	11.8	**16.9**	7.4
	29.1	22.1	**29.1**	14.4
Other, including petrochemicals	**17.4**	13.4	**16.6**	8.0
Total refined product sales	**88.9**	69.9	**86.8**	45.2
Crude oil processed by Suncor				
Eastern North America	**30.7**	25.5	**30.8**	16.2
Western North America	**36.6**	27.8	**34.0**	19.3
Total crude oil processed by Suncor	**67.3**	53.3	**64.8**	35.5

Total sales of refined petroleum products increased 27% during the third quarter of 2010, compared to the third quarter of 2009. On a comparative basis, sales volumes were positively impacted due to the timing of the merger. Overall, refinery utilization averaged 95.7% in the third quarter of 2010 which included three months of results for the Edmonton, Sarnia, Montreal and Commerce City refineries. Edmonton and Commerce City continue to operate reliably. Sarnia ran less crude in the third quarter of 2010 primarily due to the Enbridge pipeline outage which restricted crude availability from Western Canada. This shortfall was partially compensated for by the processing of international light crudes and higher utilization at Montreal to maintain product supply support for Ontario. The refinery utilization averaged 96.9% in the third quarter of 2009 post-merger which included three months of results for the Sarnia and Commerce City refineries and two months for the Edmonton and Montreal refineries.

In the first nine months of 2010, total sales of refined petroleum products averaged 86,800 m^3/d, compared to 45,200 m^3/d during the same period in 2009. The increase was primarily due to the timing of the merger.

Refinery utilization averaged 92.0% in the first nine months of 2010, with utilization of the legacy Suncor refineries averaging 95.3% compared to 97.1% over the same period in 2009.

Margins

Gross margins, in absolute terms, increased significantly when comparing the third quarter of 2010 to the third quarter of 2009 due to adding more volume as a result of the merger.

Refining and product supply activities benefited from more favorable light/heavy and light/sour synthetic crude price differentials and improved Chicago and Seattle 3:2:1 cracking margins during the third quarter of 2010 compared to the third quarter of 2009, with the cracking margin uplift being reduced by the stronger Canadian dollar relative to the U.S. dollar. These benefits were partially offset by weaker quarter over quarter New York Harbour 3:2:1 cracking margins and the processing of more expensive light crude at Sarnia in response to the crude shortfall caused by the Enbridge pipeline service disruption.

Marketing activities have benefited from the merger with increased volumes but the gross petroleum margins were down in the third quarter of 2010, compared to the same period of 2009, due to the more diversified geographic mix of the expanded retail network.

Gross margins during the first nine months of 2010 as compared to the same period in 2009 were impacted primarily by the same factors affecting the third quarter.

Operating Expenses

Operating expenses were higher in the third quarter of 2010 compared to the third quarter of 2009 primarily due to the additional month of expenses. Expenses were significantly higher in the nine months ended September 30, 2010, compared to the nine months ended September 30, 2009, due to the timing of the merger.

Depreciation, Depletion and Amortization

DD&A expenses were higher in the third quarter of 2010 and nine months ended September 30, 2010, primarily as a result of larger operations, due to the merger.

Planned Maintenance Turnarounds

At the end of September 2010 a six week turnaround began at the lubricants plant and will extend into the fourth quarter of 2010. A four week turnaround that began in September at the Montreal refinery was completed in the fourth quarter of 2010.

For planned turnarounds, the company enters into transactions to ensure sufficient additional finished product is available to mitigate the impact of lost production on customers.

Corporate, Energy Trading and Eliminations

Corporate, Energy Trading and Eliminations includes the company's investment in renewable energy projects, results related to third-party energy supply and trading activities and other activities not directly attributable to any other operating segment.

Operating Earnings Reconciliation

	Three months ended September 30		Nine months ended September 30	
($ millions)	**2010**	2009	**2010**	2009
Net (loss) earnings	**(24)**	186	**(493)**	190
Unrealized foreign exchange gain on U.S. dollar denominated long-term debt	**(220)**	(386)	**(120)**	(643)
Mark-to-market valuation of stock-based compensation	**16**	23	**(18)**	57
Merger and integration costs	**22**	51	**61**	67
Impact of income tax rate adjustments on future income tax liabilities	**—**	3	**—**	3
Operating loss[1]	**(206)**	(123)	**(570)**	(326)

(1) Non-GAAP measures.

($ millions)	Three months ended September 30 2010	2009	Nine months ended September 30 2010	2009
Operating earnings (loss)[1]				
Renewable energy	**7**	6	**29**	22
Energy trading	**11**	29	**22**	34
Corporate	**(231)**	(90)	**(633)**	(283)
Group eliminations	**7**	(68)	**12**	(99)
	(206)	(123)	**(570)**	(326)
Cash flow used in operations[1]	**(244)**	(299)	**(754)**	(351)

(1) Non-GAAP measures.

Total Corporate, Energy Trading and Eliminations net loss was $24 million in the third quarter of 2010, compared with net earnings of $186 million in the third quarter of 2009. The decrease in net earnings quarter over quarter was primarily due to a larger unrealized foreign exchange gain on U.S. dollar denominated long-term debt in the third quarter of 2009 compared to the third quarter of 2010. Excluding the earning adjustments, operating loss for the third quarter of 2010 was $206 million compared to an operating loss of $123 million for the third quarter of 2009.

Net loss for the first nine months of 2010 was $493 million, compared to net earnings of $190 million in the same period of 2009. The decrease in net earnings year over year was primarily due to a larger unrealized foreign exchange gain on U.S. dollar denominated long-term debt being booked in the nine months ended September 2009 compared to the nine months ended September 2010. Excluding the earning adjustments, operating loss for the first nine months of 2010 was $570 million, compared to an operating loss of $326 million in the same period of 2009.

Cash flow used in operations was $244 million in the third quarter of 2010, compared to $299 million in the third quarter of 2009. The decrease in cash flow used in operations is primarily due to crude oil sales between Oil Sands or East Coast Canada and Refining and Marketing where profits were recognized in the current period compared to profit eliminations in the prior period. Cash flows also included the impacts of lower merger and integration costs and higher Energy Trading contributions, partially offset by captive insurance payments made in the current quarter.

Renewable Energy

The company's renewable energy interests include four wind power projects, with a fifth project currently under construction, and Canada's largest ethanol plant by production volume. Suncor's wind projects, located in Saskatchewan, Alberta and Ontario, have a total generating capacity of 147 megawatts, offsetting the equivalent of 284,000 tonnes of carbon dioxide (CO_2) per year.

Construction began on the 88 megawatt Wintering Hills wind power project in the third quarter of 2010 and which is expected to be completed by the end of 2011. The company will have a 70 percent interest in and operate the project, with Teck Resources Limited owning the remaining 30 percent interest. At peak operation, the project is expected to generate enough electricity to power approximately 35,000 Alberta homes and displace 200,000 tonnes of CO_2 per year.

The ethanol plant, located in Sarnia, Ontario, has a current capacity of 200 million litres per year, offsetting the equivalent of 300,000 tonnes of CO_2 per year. A plant expansion, currently underway, is expected to be completed on schedule by December 2010 and on budget of $120 million.

Operating earnings of $7 million were contributed from the company's renewable energy operations in the third quarter of 2010, which is consistent with the same period in 2009.

Operating earnings for the nine months ended September 30, 2010 were $29 million compared to $22 million for the nine months ended September 30, 2009. The increase is primarily due to receipt of retroactive government contributions received in the first quarter of 2010.

Energy Trading

Suncor's energy trading activities primarily involve marketing and trading of crude oil, natural gas, refined products and by-products, and the use of financial derivatives. These activities resulted in operating earnings of $11 million in the third quarter of 2010, compared to $29 million in the third quarter of 2009.

In the third quarter of 2010, the gain was driven by strong price differentials for Canadian heavy crude oil products relative to WTI. In the third quarter of 2009, results were positively impacted by realized physical gains on crude inventory positions.

Operating earnings for the nine months ended September 30, 2010 were $22 million, compared to $34 million for the nine months ended September 30, 2009. The decrease was primarily due to lower year over year earnings on crude storage strategies due to a narrowing of the difference between current and future crude prices. This was partially offset by higher year over year earnings on Canadian heavy crude strategies due to a wide differential between Canadian and U.S. heavy crude market prices.

Corporate and Eliminations

Corporate experienced an operating loss of $231 million in the third quarter of 2010, compared to an operating loss of $90 million in the third quarter of 2009. The increase was primarily the result of captive insurance expenses related to the February 2010 Oil Sands upgrader fire ($83 million after-tax), increased net interest expense, due to additional debt acquired through the merger, and lower gains on U.S. dollar denominated working capital balances.

Group eliminations reflects the elimination of profit on crude oil sales between Oil Sands or East Coast Canada and Refining and Marketing, where profits are realized when the products are sold to third parties. During the third quarter of 2010, $7 million of profits previously eliminated were recognized, compared to profits of $68 million that were eliminated in the third quarter of 2009.

Corporate operating loss for the nine months ended September 2010 was $633 million, compared to an operating loss of $283 million for the nine months ended September 2009. The increase was primarily due to captive insurance payments made in the first and third quarter of 2010 and additional interest expense.

CASH INCOME TAXES

The company estimates that it will have cash income taxes of approximately $1.0 billion to $1.1 billion during the 2010 calendar year. Cash income taxes are sensitive to crude oil and natural gas commodity price volatility, refinery cracking margins and the timing of capital expenditure deductibility for income tax purposes, among other things. This estimate was based on the following assumptions: current forecasts of commodity price, exchange rates, production, capital spending and operating costs and assumes there will be no changes to any of the current applicable income tax regimes. See the Legal Advisory – Forward-Looking Information section of this MD&A for additional material risks and assumptions underlying this forward-looking information relating to income taxes.

FINANCIAL CONDITION AND LIQUIDITY

($ millions, except ratios)	**September 30 2010**	December 31 2009
Working capital (deficit)[1]	**634**	(324)
Short-term debt	**2**	2
Current portion of long-term debt	**518**	25
Long-term debt	**11 534**	13 855
Total debt	**12 054**	13 882
Less: Cash and cash equivalents	**598**	505
Net debt	**11 456**	13 377
Shareholders' equity	**35 728**	34 111
Total capitalization (total debt & shareholders' equity)	**47 782**	47 993
Total debt to debt plus shareholders' equity (%)[2]	**25**	29

	Twelve months ended September 30	
	2010	2009
ROCE (%)[3], [8]	**7.9**	3.7
ROCE (%)[4], [8]	**5.7**	2.6
Net debt to cash flow from operations (times)[5]	**2.0**	7.0
Interest coverage on long-term debt (times)		
Net earnings[6]	**6.0**	1.9
Cash flow from operations[7], [8]	**9.7**	5.9

(1) Calculated as current assets less current liabilities, excluding cash and cash equivalents, short-term debt, current portion of long-term debt and future income taxes. Current assets and liabilities of discontinued operations are excluded.

(2) Short-term debt plus long-term debt; divided by the sum of short-term debt, long-term debt and shareholders' equity.

(3) Excludes capitalized costs related to major projects in progress.

(4) Includes capitalized costs related to major projects in progress.

(5) Short-term debt plus long-term debt less cash and cash equivalents, divided by cash flow from operations.

(6) Net earnings plus income taxes and interest expense, divided by the sum of interest expense and capitalized interest.

(7) Cash flow from operations plus current income taxes and interest expense; divided by the sum of interest expense and capitalized interest.

(8) Non-GAAP measure. See the Non-GAAP Financial measures section of this MD&A.

Capital Structure

Suncor's capital resources consist primarily of cash flow from operations and available lines of credit. Management of debt levels continues to be a priority given the company's long-term growth plans. Suncor's management believes a phased and flexible approach to existing and future growth projects should assist Suncor in maintaining its ability to manage project costs and debt levels.

At September 30, 2010, Suncor's net debt was $11.5 billion, compared to $13.4 billion at December 31, 2009. Net debt decreased by $1.9 billion largely due to the use of proceeds on asset disposition to pay down debt. Unutilized lines of credit at September 30, 2010 were approximately $5.7 billion compared to $4.2 billion at December 31, 2009.

Suncor's management believes Suncor will have the capital resources to fund its planned capital spending program and to meet current and long term working capital requirements through cash flow from operations and its available committed credit facilities. The company's cash flow from operations depends on a number of factors, including commodity prices, production/sales levels, refining and marketing margins, operating expenses, taxes, royalties, and foreign exchange rates. If

additional capital is required, the company believes adequate additional financing will be available in the debt capital markets at commercial terms and rates.

Suncor is subject to financial and operating covenants related to its public market and bank debt. Failure to meet the terms of one or more of these covenants may constitute an Event of Default as defined in the respective debt agreements, potentially resulting in accelerated repayment of one or more of the debt obligations. The company is in compliance with its financial covenant that requires total debt to not be more than 60% of its total capitalization. At September 30, 2010, total debt to total capitalization was 25% (December 31, 2009 – 29%). The company is also currently in compliance with all operating covenants.

The preceding paragraphs contain forward looking information. See the Legal Advisory – Forward-Looking Information section of this MD&A for the material risks and assumptions underlying this forward-looking information.

Outstanding Shares

At September 30, 2010	thousands
Common shares	**1 562 822**
Common share options – total	**70 763**

Credit Ratings

The following information regarding the company's credit ratings is provided as it relates to the company's cost of funds and liquidity and indicates whether or not the company's credit ratings have changed. In particular, the company's ability to access unsecured funding markets and to engage in certain collateralized business activities on a cost-effective basis is primarily dependent upon maintaining competitive credit ratings. A lowering of the company's credit rating may also have potentially adverse consequences for the company's funding capacity or access to the capital markets, may affect the company's ability, and the cost, to enter into normal course derivative or hedging transactions and may require the company to post additional collateral under certain contracts.

All of the company's debt ratings are investment grade. The company's current long term senior debt ratings are BBB+, with a Stable Outlook from Standard & Poor's (S&P); A(low), with a Stable Trend from Dominion Bond Rating Service (DBRS); and Baa2, with a Stable Outlook from Moody's Investors Service. Suncor's current commercial paper ratings are A-1 (Low) from S&P and R-1 (low) from DBRS. These have not changed from December 31, 2009.

Contractual Obligations, Commitments and Guarantees

In the normal course of business, the company is obligated to make future payments. These obligations represent contracts and other commitments that are known and non-cancellable. Suncor has included these obligations, commitments and guarantees in the section of its Annual Report entitled "Aggregate Financial Commitments" on page 14, which section of the Annual Report is incorporated herein by reference. There have been no material developments since December 31, 2009.

Capital Investment Update

Suncor spent $1.443 billion on capital and exploration in the third quarter of 2010, bringing the year-to-date spending to $3.966 billion, of the $5.5 billion budget. The capital expenditures were primarily focused on maintaining our assets throughout the company to ensure they operate safely and reliably and the continued development of Firebag Stage 3 expansion.

Oil Sands

Oil Sands capital expenditures totaled $962 million in the third quarter of 2010, bringing the year-to-date spending to $2.642 billion. Spending has been primarily focused on the construction of Firebag Stage 3.

The company is continuing with its planned growth initiatives related to the Firebag Stage 3 in situ oil sands expansion. The planned expansion is currently expected to achieve first oil production in the second quarter of 2011, with volumes ramping up over an estimated 18 to 24 month period toward planned production capacity of approximately 62,500 barrels of bitumen per day. Current year-to-date expenditures focused on construction of co-generation and central plant facilities and well pads.

The company is committed to the development of the in situ oil sands expansion and plan to develop Firebag Stage 4 which is expected to add another 62,500 barrels of bitumen per day in production capacity once full production ramp-up is achieved.

Current year to date expenditures also focused on engineering, procurement, construction and sustaining capital required to keep the mining, upgrading, extraction and in situ assets operating effectively. Spending is ongoing and will continue into the fourth quarter of 2010.

The company received regulatory approval for a new tailings management plan using the company's proprietary TRO_{TM} tailings management process in June 2010. It is anticipated that TRO_{TM} will allow the company to accelerate the pace of reclamation and reduce costs in the long term. Project activities during the third quarter included engineering, procurement of certain long lead items, site preparation and construction of temporary facilities. Phase one of the project is expected to be completed in the first quarter of 2012 and phase two is expected to be completed by the end of 2012. Capital spending for large scale implementation of TRO_{TM}, remains subject to Board of Directors approval.

Plans to complete a naphtha unit at Upgrader 2 have been delayed throughout the year due to redeployment of resources but remain a priority for the company. The project, which is intended to increase the value of the upgrader's product mix, is currently expected to be completed in the fourth quarter of 2011.

Natural Gas

Natural Gas is reviewing its strategy to meet the company's growing demand for natural gas. In the third quarter of 2010, Natural Gas spent $43 million on exploration and development activities bringing the 2010 year-to-date total to $113 million with a focus on unconventional gas opportunities, primarily land acquisitions in northeast British Columbia.

Suncor's key shallow gas producing properties near Medicine Hat, in eastern Alberta, continued with drilling and tie-in activity. In total, 195 wells were drilled in the nine month period ending September 30, 2010. Approximately 150 additional wells are expected to be drilled by year-end. Overall production from this area is expected to average 70 mmcf/d.

It is expected that in the fourth quarter of 2010, the Natural Gas business will begin two significant drilling programs: one in the Ferrier area located in central Alberta and another at Pouce Coupe in western Alberta. Both programs will carry into next year and are expected to be tied-in during the first quarter of 2011.

International and Offshore

East Coast Canada

International and Offshore spent $74 million on capital and exploration in the third quarter of 2010 related to East Coast Canada operations, bringing the year-to-date spend to $183 million. Spending has been primarily focused on the White Rose and Hibernia areas.

The North Amethyst portion of the White Rose Extensions achieved first oil in May 2010. Development drilling of 11 wells in total is planned to continue until late 2012. Data provided by a delineation well will be used to optimize future well placement. The peak year for production is expected to be in 2012 when all North Amethyst development wells are completed.

Development drilling for the first phase of the West White Rose development began in August 2010, with first oil expected by early 2011. Drilling results from Stage 1, combined with production evaluation and ongoing reservoir evaluation, are expected to define the full field development scope.

Capital spending continues on the Hibernia South Extension project, where first production is expected in 2011. In October 2010 the Development Plan Amendment application was approved. Current expectations are production from the Hibernia South Extension will average 45,000 bpd (gross) (9,000 bpd net to Suncor) in 2011.

The contract for front end engineering design of the topsides for the Hebron production platform was awarded in August 2010. First oil is expected during 2017.

International

International and Offshore expenditures on capital and exploration in the third quarter of 2010 related to International operations were $101 million, bringing the year-to-date spend to $425 million. Spending has been primarily focused on exploration drilling in Libya and Norway.

The Buzzard enhancement project started-up in mid-October 2010 with a slow ramp-up expected through to the end of the year. The project included the installation of a fourth platform with equipment to handle high sulphur content.

The Norway West Alpha rig began drilling operations at the Beta Statfjord appraisal well in August, 2010 to further appraise the Beta Brent discovery completed earlier this year.

Two seismic survey projects continue to acquire data in relation to the Libya Exploration and Production Sharing Agreements (EPSA's). Two exploration wells on the En Naga EPSA were completed in the quarter and capital spend on the non-operated development projects continues.

In Syria, the Cherrife development well was successfully drilled and confirmed gas deliverability from the targeted reservoir.

Refining and Marketing

Refining and Marketing spent $152 million on capital in the third quarter of 2010, bringing the year-to-date spending to $395 million. Spending has been primarily focused on rebranding and planned turnarounds.

Spending to date has been focused on refining assets and re-branding former Sunoco retail sites to the Petro-Canada brand. The Edmonton, Montreal, Sarnia and Commerce City refineries have completed successful turnaround work during the year to support continued safe and reliable operations.

Corporate

Corporate capital expenditures were $111 million in the third quarter of 2010 bringing the year-to-date spend to $208 million. Spending has been focused on merger integration related activities and renewable energy.

Work is underway to integrate legacy Suncor and legacy Petro-Canada systems onto one common platform as well as integrate processes, information and technology.

Construction began on the 88 megawatt Wintering Hills wind power project in the third quarter of 2010 and which is expected to be completed by the end of 2011. The company will have a 70 percent interest in and operate the project,

with Teck Resources Limited owning the remaining 30 percent interest. At peak operation, the project is expected to generate enough electricity to power approximately 35,000 Alberta homes and displace 200,000 tonnes of CO_2 per year.

The ethanol plant, located in Sarnia, Ontario, has a current capacity of 200 million litres per year, offsetting the equivalent of 300,000 tonnes of CO_2 per year. A plant expansion, currently underway, is expected to be completed on schedule by December 2010 and on budget of $120 million.

Safe Mode Costs

The company continues to incur costs related to placing certain growth projects into "safe mode" due to unfavorable market conditions at the end of 2008 and into 2009. Safe mode costs are defined as the costs of deferring the projects and maintaining the equipment and facilities in a safe manner in order to expedite remobilization when appropriate. As a result of placing certain projects into safe mode, pre-tax costs of $37 million were incurred in the third quarter of 2010 with a year to date total of $110 million. Safe mode costs of approximately $150 million to $175 million on a pre-tax basis, including costs related to the remobilization of growth projects placed into safe mode, are expected to be incurred in 2010.

The above capital investment update contains forward looking information. See the Legal Advisory – Forward-Looking Information section of this MD&A for the material risks and assumptions underlying this forward-looking information.

FINANCIAL INSTRUMENTS

Suncor periodically enters into derivative contracts such as forwards, futures, swaps, options and costless collars to hedge against the potential adverse impact of changing market prices due to changes in the underlying indices. The company also uses physical and financial energy derivatives to earn trading revenues.

Suncor accounts for its significant derivative financial instruments using the mark-to-market method. The contracts are recorded on the balance sheet at fair value at each period end, with any changes in fair value immediately recognized in net earnings.

To estimate fair value of financial instruments, the company uses quoted market prices when available, or models that utilize observable market data. In addition to market information, Suncor incorporates transaction specific details that market participants would utilize in a fair value measurement, including the impact of non-performance risk. Inputs used are characterized in determining fair value using a hierarchy that prioritizes inputs depending on the degree to which they are observable. However, these fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction.

The fair values of the company's derivative financial instruments are as follows:

($ millions)	**September 30 2010**	December 31 2009
Assets	**98**	213
Liabilities	**(204)**	(572)
Net derivative financial instruments	**(106)**	(359)

For further details on the company's derivative financial instruments at September 30, 2010, see note 6 of the unaudited Interim Consolidated Financial Statements. For a more complete discussion of Suncor's exposure to financial risks and the company's mitigation activities, see note 4 to the 2009 Audited Consolidated Financial Statements, which is incorporated herein by reference.

Risks Associated with Derivative Financial Instruments

Suncor's strategic crude oil hedging program is subject to periodic management reviews to determine appropriate hedge requirements in light of our tolerance for exposure to market volatility, as well as the need for stable cash flow to finance future growth.

The company may be exposed to certain losses in the event that the counterparties to derivative financial instruments are unable to meet their obligations to Suncor. This risk is minimized by entering into agreements with investment grade counterparties. Risk is also minimized through regular management review of the potential exposure to and credit ratings of such counterparties.

Energy marketing and trading activities are governed by a separate risk management function which reviews and monitors practices and policies and provides independent verification and valuation of these activities.

RISK FACTORS AFFECTING PERFORMANCE

The company's financial and operational performance is potentially affected by a number of factors including, but not limited to, commodity prices and foreign currency exchange rates, environmental regulations, changes to royalty and income tax legislation, credit market conditions, stakeholder support for activities and growth plans, extreme weather, regional labour issues and other issues discussed within the Legal Advisory – Forward-Looking Information section of this MD&A. A more detailed discussion of the risk factors affecting the company is presented on pages 54 to 62 of the 2009 AIF, which section of the 2009 AIF is incorporated herein by reference. The company is continually working to mitigate the impact of potential risks to its stakeholders. This process includes an entity-wide risk review. This internal review is completed annually to ensure all significant risks are identified and appropriately managed.

Environmental Regulation and Risk

Environmental regulation affects nearly all aspects of our operations. These regulatory regimes are laws of general application that apply to us in the same manner as they apply to other companies and enterprises in the energy industry. The regulatory regimes require us to obtain operating licenses and permits in order to operate, and impose certain standards and controls on activities relating to mining, oil and gas exploration, development and production, and the refining, distribution and marketing of petroleum products and petrochemicals. Environmental assessments and regulatory approvals are generally required before initiating most new projects or undertaking significant changes to existing operations. In addition to these specific, known requirements, we expect future changes to environmental legislation, including anticipated legislation for air emissions (Criteria Air Contaminants (CACs) and Greenhouse Gases (GHGs)), will impose further requirements on companies operating in the energy industry.

For further discussion of environmental regulation and risks affecting the company, see the section entitled "Environmental Regulation and Risk" starting on page 21 of Suncor's 2009 Annual Report, which section of Suncor's 2009 Annual Report is incorporated herein by reference.

CRITICAL ACCOUNTING ESTIMATES

Critical accounting estimates are defined as estimates that are important to the portrayal of the company's financial position and operations, and require management to make judgments based on underlying assumptions about future events and their effects. These underlying assumptions are based on historical experience and other factors that management believes to be reasonable under the circumstances, and are subject to change as new events occur, as more industry experience is acquired, as additional information is obtained and as the company's operating environment changes. Critical accounting estimates are reviewed annually by the Audit Committee of the Board of Directors. A detailed

description of the critical accounting estimates is contained in the section entitled "Critical Accounting Estimates" on pages 23 to 25 of the 2009 Annual Report, which section of the 2009 Annual Report is incorporated herein by reference.

ACCOUNTING POLICIES

International Financial Reporting Standards

IFRS Conversion Project

The company's IFRS conversion project continues to be on target to meet the January 1, 2011 changeover date. The following is a status update of the IFRS conversion project. A description of key activities and milestones is presented on page 30 of Suncor's 2009 Annual Report. Note that new and revised IFRS developments will be monitored throughout the project and may result in changes to the project activities.

IFRS Financial Statement Preparation

Presented preliminary draft IFRS first quarter 2010 financial statements and an overview of IFRS annual pro-forma presentation changes to the IFRS Steering Committee and Audit Committee in the third quarter of 2010. Proposal for the IFRS note disclosure in the first quarter of 2011 will be presented to the IFRS Steering and Audit Committee in the fourth quarter of 2010. Audit procedures of the IFRS January 1, 2010 opening Balance Sheet by the company's external auditors is in progress. The company's external auditors will perform audit procedures on the draft IFRS quarterly financial statements in the fourth quarter of 2010.

IFRS Training

Training and communication sessions, including IFRS Knowledge Transfer Sessions, continued for management, Financial Reporting and key individuals within the Business. Regular reporting and training has continued for the company's senior executive management and the Audit Committee.

IFRS Infrastructure

Significant IFRS Information Technology activities were completed during the third quarter including testing of 2011 conversion plan and recording of the draft IFRS opening Balance Sheet adjustments. The remaining 2010 IFRS opening balance sheet adjustments will be recorded in the system in the fourth quarter of 2010 as they are completed. Implementation of business process changes is ongoing.

IFRS Control Environment

Internal controls over business process and system changes have been designed for high impact areas. Analysis to date continues to support the conclusion that no material changes will be required to internal and disclosure controls over financial reporting. Testing of internal control documentation related to the preparation of the 2010 IFRS financial statements will be completed in the fourth quarter of 2010.

IFRS Expected Accounting Policy Impacts

The major accounting policy choices outlined in Suncor's 2009 Annual Report continue to be the company's most significant areas of impact; however, analysis of changes will be ongoing throughout 2010. Preparation of the IFRS opening Balance Sheet confirmed certain balances reported under IFRS will differ from Canadian GAAP for property, plant and equipment, asset retirement obligations (ARO), share-based payments, income taxes and employee benefits. The following discussion provides further details on the accounting policy choices and changes made to prepare the draft IFRS opening Balance Sheet, including exemptions available under IFRS 1, "First-Time Adoption of International Financial

Reporting Standards". IFRS 1 provides entities adopting IFRS for the first time with a number of optional exemptions and mandatory exceptions, in certain areas, to the general requirement for full retrospective application of IFRS.

- **Property, Plant & Equipment (PP&E)**

  Although the principles of componentization and derecognition exist under both IFRS and Canadian GAAP, the standards are not identical in all respects. Under IFRS, the basis that the Company has used to apply these principles will be refined with a lower component level resulting in a decrease to the January 1, 2010 balance of PP&E and subsequent reduction to depreciation expense in 2010.

  Upon adoption to IFRS, the Company will reclassify Exploration and Evaluation (E&E) expenditures that are currently included in the PP&E balance on the Consolidated Balance Sheet. E&E assets include unproven land, exploratory drilling and exploratory project costs.

  Analysis of opening Balance Sheet and quarterly impairments of PP&E assets is ongoing.

- **Provisions, Contingent Liabilities and Contingent Assets**

  The Company is planning to utilize the IFRS 1 exemption permitting the re-calculation of the ARO at January 1, 2010. In addition, the Company has made a preliminary decision to discount the estimated fair value of its ARO using the credit adjusted risk-free rate. However the discount rate under IFRS at transition differs from the rate utilized for Canadian GAAP. These differences will increase the ARO and decreased the related PP&E assets as at January 1, 2010.

- **Share-Based Payments**

  IFRS 2 requires that cash-settled share-based payments to employees are measured (both initially and at each reporting period) based on the fair values of the awards. Canadian GAAP requires that such payments be measured based on the intrinsic values of the awards. This difference will result in an increase to Suncor's share-based payments liability at January 1, 2010.

- **Employee Benefits**

  The company has opted to elect the IFRS 1 exemption to recognize all cumulative actuarial gains and losses existing at the date of transition immediately in retained earnings.

- **Foreign Exchange**

  First time adopters of IFRS can elect upon adoption to deem cumulative translation differences to be zero at date of transition. The Company has elected to take this IFRS 1 exemption which will result in a reclassification from other reserves (previously termed "accumulated other comprehensive income") to retained earnings.

- **Income Taxes**

  In transitioning to IFRS, the company's future tax liability is impacted by the tax effects resulting from the IFRS changes discussed above.

IFRS: Other Accounting Policy Choices

Business combinations and joint ventures entered into prior to January 1, 2010 will not be retrospectively restated using IFRS principles.

Additional IFRS accounting policy choices and changes have not had a material impact on the IFRS opening Balance Sheet to-date and will continue to be monitored throughout the IFRS conversion project.

Control Environment

Based on their evaluation as of September 30, 2010, Suncor's chief executive officer and chief financial officer concluded that the company's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the United States Securities Exchange Act of 1934 (the Exchange Act)) are effective to ensure that information required to be disclosed by the company in reports that are filed or submitted to Canadian and U.S. securities authorities is recorded, processed, summarized and reported within the time periods specified in Canadian and U.S. securities laws. In addition, as of September 30, 2010, there were no changes in the internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) – 15d-15(f)) that occurred during the three-month period ended September 30, 2010 that have materially affected, or are reasonably likely to materially affect, the company's internal control over financial reporting. Management will continue to periodically evaluate the company's disclosure controls and procedures and internal control over financial reporting and will make any modifications from time to time as deemed necessary.

The company continues to integrate Petro-Canada's historical internal control over financial reporting with its internal control over financial reporting. This integration will lead to changes in these controls in future fiscal periods but it is not yet known whether these changes will materially affect internal control over financial reporting. This integration process is expected to be substantially completed by the end of 2011.

Based on their inherent limitations, disclosure controls and procedures and internal control over financial reporting may not prevent or detect misstatements, and even those controls determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

NON-GAAP FINANCIAL MEASURES

Certain financial measures referred to in this MD&A, namely operating earnings, cash flow from operations, return on capital employed (ROCE), and cash and total operating costs are not prescribed by Canadian GAAP. These non-GAAP financial measures do not have any standardized meaning and therefore are unlikely to be comparable to similar measures presented by other companies. These non-GAAP financial measures are included because management uses this information to analyze operating performance, leverage and liquidity. The additional information should not be considered in isolation or as a substitute for measures of performance prepared in accordance with Canadian GAAP.

Return on Capital Employed (ROCE)

ROCE is included because management uses this information to analyze operating performance, leverage and liquidity. A detailed numerical reconciliation of ROCE is provided on an annual basis in the company's annual MD&A, which is to be read in conjunction with the company's annual Consolidated Financial Statements. For a summarized narrative reconciliation of ROCE calculated on a September 30, 2010 interim basis, please refer to the Highlights Supplement.

Operating Earnings

Operating earnings is a non-GAAP measure that adjusts net earnings for significant items that are not indicative of operating performance that management believes reduces the comparability of the underlying financial performance between periods. Management uses operating earnings to evaluate operating performance, because management believes it provides better comparability between periods. All reconciling items are presented on an after-tax basis.

Cash Flow from Operations

Cash flow from operations is expressed before changes in non-cash working capital.

Three months ended September 30 ($ millions)	Oil Sands		Natural Gas		International and Offshore		Refining and Marketing		Corporate, Energy Trading and Eliminations		Total	
	2010	2009	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009
Net earnings (loss) from continuing operations	**412**	738	**(167)**	(97)	**236**	93	**152**	45	**(24)**	186	**609**	965
Adjustments for:												
Depreciation, depletion and amortization	**298**	242	**330**	97	**307**	81	**120**	96	**15**	7	**1 070**	523
Future income taxes	**142**	(9)	**(52)**	(20)	**(27)**	14	**49**	14	**(20)**	(98)	**92**	(99)
Accretion of asset retirement obligations	**30**	30	**7**	5	**7**	3	**—**	—	**—**	—	**44**	38
Unrealized (gain) loss on translation of U.S. dollar denominated long-term debt	**—**	—	**—**	—	**—**	—	**—**	—	**(252)**	(400)	**(252)**	(400)
Change in fair value of derivative contracts	**(39)**	(302)	**—**	(1)	**—**	—	**1**	4	**38**	(34)	**—**	(333)
Loss (gain) on disposal of assets	**—**	—	**(89)**	(5)	**—**	—	**(16)**	(5)	**—**	—	**(105)**	(10)
Stock-based compensation	**23**	39	**8**	13	**6**	11	**16**	23	**27**	39	**80**	125
Gain on effective settlement of pre-existing contract with Petro-Canada	**—**	(438)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	(438)
Other	**(87)**	(58)	**18**	(2)	**—**	33	**4**	87	**(28)**	1	**(93)**	61
Exploration expenses	**—**	—	**1**	49	**39**	3	**—**	—	**—**	—	**40**	52
Total cash flow from (used in) operations from continuing operations	**779**	242	**56**	39	**568**	238	**326**	264	**(244)**	(299)	**1 485**	484
Total cash flow from (used in) operations from discontinued operations	**—**	—	**21**	35	**124**	55	**—**	—	**—**	—	**145**	90
Total cash flow from (used in) operations	**779**	242	**77**	74	**692**	293	**326**	264	**(244)**	(299)	**1 630**	574

Nine months ended September 30 ($ millions)	Oil Sands 2010	Oil Sands 2009	Natural Gas 2010	Natural Gas 2009	International and Offshore 2010	International and Offshore 2009	Refining and Marketing 2010	Refining and Marketing 2009	Corporate, Energy Trading and Eliminations 2010	Corporate, Energy Trading and Eliminations 2009	Total 2010	Total 2009
Net earnings (loss) from continuing operations	**1 005**	321	**(212)**	(130)	**662**	93	**429**	256	**(493)**	190	**1 391**	730
Adjustments for:												
Depreciation, depletion and amortization	**1 021**	622	**647**	174	**870**	81	**352**	203	**49**	23	**2 939**	1 103
Future income taxes	**340**	(540)	**(74)**	(16)	**5**	14	**128**	95	**(138)**	(67)	**261**	(514)
Accretion of asset retirement obligations	**90**	82	**20**	8	**20**	3	**2**	1	**—**	—	**132**	94
Unrealized (gain) loss on translation of U.S. dollar denominated long-term debt	**—**	—	**—**	—	**—**	—	**—**	—	**(136)**	(657)	**(136)**	(657)
Change in fair value of derivative contracts	**(250)**	988	**—**	(1)	**—**	—	**—**	(19)	**(3)**	71	**(253)**	1 039
Loss (gain) on disposal of assets	**11**	17	**(126)**	(20)	**—**	—	**(19)**	15	**1**	—	**(133)**	12
Stock-based compensation	**36**	76	**(4)**	15	**—**	11	**10**	30	**(42)**	96	**—**	228
Gain on effective settlement of pre-existing contract with Petro-Canada	**—**	(438)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	(438)
Other	**(279)**	(232)	**5**	(3)	**10**	33	**15**	82	**8**	(7)	**(241)**	(127)
Exploration expenses	**—**	—	**14**	80	**60**	3	**—**	—	**—**	—	**74**	83
Total cash flow from (used in) operations from continuing operations	**1 974**	896	**270**	107	**1 627**	238	**917**	663	**(754)**	(351)	**4 034**	1 553
Total cash flow (used in) operations from discontinuing operations	**—**	—	**124**	62	**354**	55	**—**	—	**—**	—	**478**	117
Total cash flow from (used in) operations	**1 974**	896	**394**	169	**1 981**	293	**917**	663	**(754)**	(351)	**4 512**	1 670

Legal Advisory – Forward-Looking Information

This Management's Discussion and Analysis contains certain forward-looking statements and other information that are based on Suncor's current expectations, estimates, projections and assumptions that were made by the company in light of its experience and its perception of historical trends.

All statements and other information that address expectations or projections about the future, including statements and other information identified as forward-looking information throughout this MD&A and other statements and information about Suncor's strategy for growth, expected and future expenditures, commodity prices, costs, schedules, production volumes, operating and financial results and expected impact of future commitments, are forward-looking statements. Some of the forward-looking statements and information may be identified by words like "expects," "anticipates," "estimates," "plans," "scheduled," "intends," "believes," "projects," "indicates," "could," "focus," "vision," "goal," "outlook," "proposed," "target," "objective," and similar expressions. Forward-looking statements in this Management's Discussion and Analysis include references to:

- *expected or assumed future commodity prices and differentials and the US$/Cdn$ exchange rate;*
- *oil and gas production levels;*
- *the ability of Suncor and the purchaser to meet the conditions of closing, the expected timing of closing and the consideration to be received with respect to certain of Suncor's U.K. Offshore assets;*
- *anticipated Oil Sands and East Coast Canada royalties;*
- *continued operational reliability of refinery assets;*
- *taxes payable by Suncor, including estimated income taxes of approximately $1.0 billion to $1.1 billion during the 2010 calendar year;*
- *planned turnarounds and maintenance, including the: (i) scheduled coker annual maintenance for Upgrader 1 in the fourth quarter of 2010, and the expectation that it will last for five weeks in total and that impact from the maintenance is expected to be minimal as coker rates in Upgrader 2 are expected to be increased to mitigate the outage; (ii) three week turnaround scheduled for White Rose in the fourth quarter of 2010; and (iii) six week turnaround at Suncor's lubricants plant.*
- *the Wintering Hills Wind Power project, including the estimated completion time (the end of 2011) and the expectation that at peak operation, the project will be able to generate enough clean electricity to power approximately 35,000 Alberta homes and displace 200,000 tonnes of carbon dioxide a year;*
- *the planned expansion of Suncor's ethanol plant, including timing (to be completed on schedule by December 2010) and budget ($120 million);*
- *planned expansion for Firebag Stage 3, including the expectation that it will achieve first production in the second quarter of 2011, with volumes ramping up over an estimated 18 to 24 month period toward planned production capacity of approximately 62,500 barrels of bitumen a day;*
- *planned expansion for Firebag Stage 4, including the expectation that it will add another 62,500 barrels of bitumen a day;*
- *timelines for completion of scheduled phases of TRO technology;*
- *anticipated completion date for the naphtha unit at Upgrader 2, being the fourth quarter of 2011, and the ability of the completed naphta unit to increase the value of the upgrader's product mix;*
- *drilling and tie-in activity in and around Medicine Hat, including the plan to drill an additional 150 wells by year end with expected production to average 70 mmcf/d;*
- *planned commencement (fourth quarter of 2010) and tie-in (first quarter of 2011) of two significant drilling programs in Ferrier and Pouce Coupe in western Alberta;*
- *developmental drilling plans for and anticipated production from the White Rose Extension (including the expectation that developmental drilling for the North Amethyst portion of the extension will produce 11 wells in total and will continue until late 2012 with peak production expected to occur in 2012) and West White Rose (scheduled first oil to be early 2011);*
- *expectation that production from the Hibernia South extension in 2011 will be 45,000 bpd (gross) and 9,000 bpd (net);*
- *anticipated first oil from Hebron production platform in 2017;*
- *estimated timelines for the Buzzard Enhancement Project;*
- *anticipated liquidity and capital resources and Suncor's ability to comply with financial and operating covenants related to public market and bank debt; and*
- *anticipated safe mode costs ($150 million to $175 million on a pre-tax basis for 2010).*

Forward-looking statements and information are not guarantees of future performance and involve a number of risks and uncertainties, some that are similar to other oil and gas companies and some that are unique to Suncor. Suncor's actual results may differ materially from those expressed or implied by its forward-looking statements and information and readers are cautioned not to place undue reliance on them.

The financial and operating performance of the company's businesses, including Oil Sands, Natural Gas, International and Offshore and Refining and Marketing, are potentially affected by a number of factors, including, but not limited to, the following:

Factors that affect our Oil Sands business

- *Production reliability risk. Our ability to reliably operate our oil sands facilities in order to meet production targets.*
- *Our ability to finance oil sands growth and sustaining capital expenditures in a volatile commodity pricing environment. Also, refer to the Financial Condition and Liquidity section of this MD&A.*
- *Bitumen supply. Availability of third party bitumen, ore grade quality, unplanned mine equipment and extraction plant maintenance, tailings storage and in situ reservoir and equipment performance could impact 2010 production targets.*
- *Performance of recently commissioned facilities. Production rates while new equipment is being lined out are difficult to predict and can be impacted by unplanned maintenance.*

- *Ability to manage production operating costs. Operating costs could be impacted by inflationary pressures on labour, volatile pricing for natural gas used as an energy source in oil sands processes, and planned and unplanned maintenance. We continue to address these risks through strategies such as application of technologies that help manage operational workforce demand, offsetting natural gas purchases through internal production, investigation of technologies that mitigate reliance on natural gas as an energy source, and an increased focus on preventative maintenance.*
- *Our ability to complete projects both on time and on budget. This could be impacted by competition from other projects (including other oil sands projects) for goods and services and demands on infrastructure in Fort McMurray and the surrounding area (including housing, roads and schools). We continue to address these issues through a comprehensive recruitment and retention strategy, working with the community to determine infrastructure needs, designing Oil Sands expansion to reduce unit costs, seeking strategic alliances with service providers and maintaining a strong focus on engineering, procurement and project management.*
- *Potential changes in the demand for refinery feedstock and diesel fuel. Our strategy is to reduce the impact of this issue by entering into long-term supply agreements with major customers, expanding our customer base and offering a variety of blends of refinery feedstock to meet customer specifications.*
- *Volatility in light/heavy and sweet/sour crude oil differentials.*
- *Logistical constraints and variability in market demand, which can impact crude movements. These factors can be difficult to predict and control.*
- *Changes to royalty and tax legislation and related agreements that could impact our business. While fiscal regimes in Alberta and Canada are generally stable relative to many global jurisdictions, royalty and tax treatments are subject to periodic review, the outcome of which is not predictable and could result in changes to the company's planned investments, and rates of return on existing investments.*
- *Our relationship with our trade unions. Work disruptions have the potential to adversely affect Oil Sands operations and growth projects.*

Factors that affect our Natural Gas business

- *The accessibility and cost of mineral rights. Market demand influences the cost and available opportunities for mineral leases and acquisitions.*
- *Volatility in natural gas prices.*
- *Risk associated with a depressed market for asset sales, leading to losses on disposition.*
- *Risks and uncertainties associated with weather conditions, which can shorten the winter drilling season and impact the spring and summer drilling program, which may result in increased costs and/or delays in bringing on new production.*

Factors that affect our International and Offshore business

- *Risks and uncertainties associated with international and offshore operations normally inherent in such activities such as drilling, operation and development of such properties including unexpected formations or pressures, premature declines of reservoirs, fires, blow-outs, equipment failures and other accidents, uncontrollable flows of crude oil, natural gas or well fluids, pollution and other environmental risks.*
- *Performance after completion of maintenance is not predictable and can significantly impact production rates.*
- *Risks and uncertainties associated with consulting with stakeholders and obtaining regulatory approval for exploration and development activities. These risks could increase costs and/or cause delays to or cancellation of projects and expansions to existing projects.*
- *Risks and uncertainties associated with weather conditions, which may result in increased costs and/or delays in exploration, operations or abandonment activities.*
- *Suncor's foreign operations and related assets are subject to a number of political, economic and socio-economic risks. Suncor's operations in Libya may be constrained by production quotas.*

Factors that affect our Refining and Marketing business

- *Production reliability risk. Our ability to reliably operate our refining and marketing facilities in order to meet production targets.*
- *Management expects that fluctuations in demand and supply for refined products, margin and price volatility, and market competition, including potential new market entrants, will continue to impact the business environment.*
- *There are certain risks associated with the execution of capital projects, including the risk of cost overruns. Numerous risks and uncertainties can affect construction schedules, including the availability of labour and other impacts of competing projects drawing on the same resources during the same time period.*
- *Our relationship with our trade unions. Hourly employees at our London, Ontario terminal operation, our Sarnia refinery, our Commerce City refinery, our Montreal refinery, certain of our lubricants operations, certain of our terminalling operations and at Sun-Canadian Pipeline Company Limited are represented by labour unions or employee associations. Any work interruptions involving our employees, and/or contract trades utilized in our projects or operations, could have a material adverse effect on our business, financial condition, results of operations and cash flow.*

Oil Sands Royalties

The percentages disclosed in the table (the "Oil Sands Table") on page 19 of the MD&A, which includes our estimation of royalties for our Oil Sands operations (excluding Syncrude) in the years 2010 to 2013 under three price scenarios, were developed using the following assumptions: current agreements with the Government of Alberta remaining in force, royalty rates and other changes enacted effective January 1, 2009 by the Government of Alberta remaining in force, current forecasts of production, capital and operating costs, and the forward estimates of commodity prices and exchange rates described in the Oil Sands Table. The following risk factors could cause actual royalty rates to differ materially from the rates contained in Oil Sands Table:

(i) The Government of Alberta enacted new Bitumen Valuation Methodology (Ministerial) Regulations as part of the implementation of the New Royalty Framework effective January 1, 2009. These interim regulations determine the valuation of bitumen for 2009 and 2010. The final regulations are being developed by the Crown that will establish the bitumen valuation methodology for future years. For Suncor's mining operations, the bitumen valuation methodology is based on the terms of Suncor's January 2008 Royalty Amending Agreement (Suncor RAA), which the company believes places certain limitations on the interim bitumen valuation methodology as recently enacted. Suncor filed a non-compliance notice with the Crown, citing that reasonable adjustments in the determination of the Suncor bitumen value were not considered by the Crown as required by the Suncor RAA. Royalty payments to the Crown for Suncor's mining operations were determined in accordance with the Suncor RAA and royalty expense was

recorded under the Crown's interim bitumen valuation methodology, resulting in a reserve of approximately $308 million at September 30, 2010. The Suncor RAA provides for a negotiation period with the Crown and, failing a negotiated settlement, an arbitration procedure is outlined. If a negotiated settlement is not reached or an arbitrator does not rule in favour of Suncor, royalty payments could be significantly higher.

(ii) The Government of Alberta enacted the new Oil Sands Allowed Costs (Ministerial) Regulations as part of the implementation of the New Royalty Framework effective January 1, 2009. Further clarification of some Allowed Cost business rules is still expected. The terms of the Suncor RAA determine the royalty obligation through 2015 for the mining operations. However, potential changes to, and the interpretation of, the Allowed Cost Regulations, could over time, have a significant impact on the amount of royalties payable.

(iii) Changes in crude oil and natural gas pricing, production volumes, foreign exchange rates, and capital and operating costs for each oil sands project; changes resulting from regulatory audits of prior year filings; further changes to applicable royalty regimes by the Government of Alberta; changes in other legislation; and the occurrence of unexpected events such as unplanned turnarounds, fires, and shutdowns, all have the potential to have a material impact on royalties payable to the Crown.

For further information on risk factors related to royalty rates for our Oil Sands operations, please refer to page 59 of the 2009 AIF, which risk factors are incorporated herein by reference.

East Coast Canada Royalties

The percentages disclosed in the table (the "East Coast Canada Table") on page 28 of the MD&A, which includes our estimation of royalties for our International operations for 2010 to 2013 under three price scenarios, were developed using the following assumptions: current agreements with the government of Newfoundland and Labrador remain in force, unamended, current forecasts of production, capital and operating costs, and the forward estimates of commodity prices and exchange rates described in the East Coast Canada Table. The following risk factors could cause actual royalty rates to differ materially from the rates contained in the East Coast Canada Table:

(i) The government of Newfoundland and Labrador and Suncor are in discussions to resolve several outstanding issues that impact current and prior years. Settlement of these issues could have a material impact on royalties payable to the Crown.

(ii) Changes in crude oil and natural gas pricing, production volumes, foreign exchange rates, and capital and operating costs for each project; changes resulting from regulatory audits of prior year filings; further changes to applicable royalty regimes by the government of Newfoundland and Labrador; changes in other legislation; and the occurrence of unexpected events all have the potential to have a material impact on royalties payable to the Crown.

For further information on risk factors related to royalty rates for our I&O Operations, please refer to page 18 of our 2009 Annual Report, which risk factors are incorporated herein by reference.

Additional Risks, Uncertainties and Other Factors

Additional risks, uncertainties and other factors that could influence actual results of all of Suncor's business segments include but are not limited to, market instability affecting Suncor's ability to borrow in the capital debt markets at acceptable rates; consistently and competitively finding and developing reserves that can be brought on-stream economically; success of hedging strategies; maintaining a desirable debt to cash flow ratio; changes in the general economic, market and business conditions; our ability to finance capital investment to replace reserves or increase processing capacity in a volatile commodity pricing and credit environment (also refer to the Financial Condition and Liquidity section of this MD&A); fluctuations in supply and demand for Suncor's products; commodity prices, interest rates and currency exchange rates (we mitigate some of the risk associated with changes in commodity prices through the use of derivative financial instruments as discussed in the Financial Instruments section of this MD&A); volatility in natural gas and liquids prices is not predictable and can significantly impact revenues; Suncor's ability to respond to changing markets and to receive timely regulatory approvals; the successful and timely implementation of capital projects including growth projects and regulatory projects; risks and uncertainties associated with consulting with stakeholders and obtaining regulatory approval for exploration and development activities in our operating areas (these risks could increase costs and/or cause delays to or cancellation of projects); effective execution of planned turnarounds; the accuracy of cost estimates, some of which are provided at the conceptual or other preliminary stage of projects and prior to commencement or conception of the detailed engineering needed to reduce the margin of error and increase the level of accuracy; the integrity and reliability of Suncor's capital assets; the cumulative impact of other resource development; the cost of compliance with current and future environmental laws; the accuracy of Suncor's reserve, resource and future production estimates and its success at exploration and development drilling and related activities; the maintenance of satisfactory relationships with unions, employee associations and joint venture partners; competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternative sources of energy; labour and material shortages; uncertainties resulting from potential delays or changes in plans with respect to projects or capital expenditures; actions by governmental authorities including the imposition of taxes or changes to fees and royalties, changes in environmental and other regulations (for example, the Government of Alberta's review of the unintended consequences of the proposed Crown royalty regime, the Government of Canada's current review of greenhouse gas emission regulations); the ability and willingness of parties with whom we have material relationships to perform their obligations to us (including in respect of any planned divestitures); risks and uncertainties associated with the ability of closing conditions to be met, the timing of closing and the consideration to be received with respect to the planned sale of any of Suncor's assets, including the ability of counterparties to comply with their obligations in a timely manner and the receipt of any required regulatory or other third party approvals outside of Suncor's control; the occurrence of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting Suncor or other parties whose operations or assets directly or indirectly affect Suncor; failure to realize anticipated synergies or cost savings; risks regarding the integration of the two businesses after the merger; and incorrect assessments of the values of Petro-Canada. The foregoing important factors are not exhaustive.

Many of these risk factors and other assumptions related to Suncor's forward-looking statements and information are discussed in further detail throughout this Management's Discussion and Analysis and in Suncor's Annual Information Form/Form 40-F on file with Canadian securities commissions at www.sedar.com and the United States Securities and Exchange Commission (SEC) at www.sec.gov. Readers are also referred to the risk factors and assumptions described in other documents that Suncor files from time to time with securities regulatory authorities. These risk factors and assumptions are incorporated herein by reference. Copies of these documents are available without charge from the company.

Highlights

(unaudited)

	2010	2009
Cash Flow From Operations		
(dollars per common share – basic)		
For the three months ended September 30		
Cash flow from operations[1]	**1.04**	0.43
For the nine months ended September 30		
Cash flow from operations[1]	**2.89**	1.55
Ratios		
For the twelve months ended September 30		
Return on capital employed (%)[2]	**7.9**	3.7
Return on capital employed (%)[3]	**5.7**	2.6
Net debt to cash flow from operations (times)[4]	**2.0**	7.0
Interest coverage on long-term debt (times)		
Net earnings[5]	**6.0**	1.9
Cash flow from operations[6]	**9.7**	5.9
As at September 30		
Total debt to total debt plus shareholders' equity (%)[7]	**25**	29
Common Share Information		
As at September 30		
Share price at end of trading		
Toronto Stock Exchange – Cdn$	**33.50**	37.40
New York Stock Exchange – US$	**32.55**	34.56
Common share options outstanding (thousands)	**70 763**	73 784
For the nine months ended September 30		
Average number outstanding, weighted monthly (thousands)	**1 561 650**	1 061 074

Refer to the Quarterly Operating Summary for a discussion of financial measures not prepared in accordance with Canadian generally accepted accounting principles (GAAP).

(1) Cash flow from operations for the period; divided by the weighted average number of common shares outstanding during the period.

(2) For the twelve-month period ended; net earnings (2010 – $2,720 million; 2009 – $672 million) after adjustment to add back after-tax financing expense (2010 – $45 million; 2009 – $198 million) divided by average capital employed (2010 – $34,496 million; 2009 – $18,107 million). Average capital employed is shareholders' equity and short-term debt plus long-term debt less cash and cash equivalents, less capitalized costs related to major projects in progress (as applicable), on a weighted-average basis.

(3) If capital employed were to include capitalized costs related to major projects in progress (average capital employed including major projects in progress: 2010 – $47,319 million; 2009 – $26,246 million), the return on capital employed would be as stated on this line.

(4) Short-term debt plus long-term debt less cash and cash equivalents, divided by cash flow from operations for the twelve-month period then ended.

(5) Net earnings plus income taxes and interest expense, divided by the sum of interest expense and capitalized interest.

(6) Cash flow from operations plus current income taxes and interest expense; divided by the sum of interest expense and capitalized interest.

(7) Short-term debt plus long-term debt; divided by the sum of short-term debt, long-term debt and shareholders' equity.

Quarterly Operating Summary

(unaudited)

	Three months ended					Nine months ended		Twelve months ended
	Sept 30 2010	June 30 2010	Mar 31 2010	Dec 31 2009	Sept 30 2009	**Sept 30 2010**	Sept 30 2009	Dec 31 2009
OIL SANDS								
Production [a]								
Total production (excluding Syncrude)	**306.6**	295.5	202.3	278.9	305.3	**268.6**	294.8	290.6
Firebag [k]	**50.4**	55.7	55.7	51.1	54.3	**53.9**	48.4	49.1
MacKay River [k]	**28.8**	32.5	31.8	31.7	26.5***	**31.0**	26.5***	29.7***
Syncrude	**31.7**	38.9	32.3	39.3	37.4***	**34.3**	37.4***	38.5***
Sales [a] (excluding Syncrude)								
Light sweet crude oil	**84.5**	99.0	61.0	100.8	89.6	**81.6**	99.2	99.6
Diesel	**25.8**	30.7	12.9	31.4	36.9	**23.2**	28.4	29.1
Light sour crude oil	**165.8**	143.1	80.5	142.4	146.8	**130.1**	133.5	135.7
Bitumen	**21.2**	37.4	42.3	13.0	14.3	**33.6**	11.3	11.8
Total sales	**297.3**	310.2	196.7	287.6	287.6	**268.5**	272.4	276.2
Average sales price [1], [b] (excluding Syncrude)								
Light sweet crude oil*	**75.49**	77.55	80.84	77.71	71.99	**77.63**	63.68	67.26
Other (diesel, light sour crude oil and bitumen)*	**66.39**	68.53	69.53	72.93	67.51	**67.95**	61.01	64.18
Total*	**68.97**	71.41	73.03	74.61	68.91	**70.89**	61.98	65.29
Total	**67.53**	69.79	70.21	65.42	62.01	**69.05**	60.32	61.66
Syncrude average sales price [1], [b]	**78.83**	77.32	83.21	78.81	75.17	**79.79**	75.17	77.36
Cash operating costs and Total operating costs – Total operations (excluding Syncrude) [c]								
Cash costs	**32.95**	32.70	46.50	35.10	30.65	**36.20**	30.30	31.50
Natural gas	**0.60**	2.55	5.40	3.40	1.55	**2.50**	2.05	2.40
Imported bitumen	**0.05**	0.65	2.95	0.20	0.05	**1.00**	0.05	0.05
Cash operating costs [2]	**33.60**	35.90	54.85	38.70	32.25	**39.70**	32.40	33.95
Project start-up costs	**0.75**	0.55	0.55	0.50	0.45	**0.60**	0.45	0.45
Total cash operating costs [3]	**34.35**	36.45	55.40	39.20	32.70	**40.30**	32.85	34.40
Depreciation, depletion and amortization	**9.00**	15.35	12.65	10.00	7.60	**12.25**	7.35	8.00
Total operating costs [4]	**43.35**	51.80	68.05	49.20	40.30	**52.55**	40.20	42.40
Cash operating costs and Total operating costs – Syncrude [c]****								
Cash costs	**39.20**	28.75	39.60	29.65	29.50	**35.40**	29.50	29.60
Natural gas	**2.75**	2.85	4.50	3.45	2.10	**3.30**	2.10	2.90
Cash operating costs [2]	**41.95**	31.60	44.10	33.10	31.60	**38.70**	31.60	32.50
Project start-up costs	**—**	—	—	—	—	**—**	—	—
Total cash operating costs [3]	**41.95**	31.60	44.10	33.10	31.60	**38.70**	31.60	32.50
Depreciation, depletion and amortization	**14.85**	11.35	13.70	11.80	12.70	**13.15**	12.70	12.15
Total operating costs [4]	**56.80**	42.95	57.80	44.90	44.30	**51.85**	44.30	44.65
Cash operating costs and Total operating costs – In situ bitumen production only [c]								
Cash costs	**17.15**	13.65	12.30	14.25	13.25	**14.30**	14.70	14.55
Natural gas	**5.25**	5.05	7.05	6.05	4.30	**5.80**	5.55	5.70
Cash operating costs [5]	**22.40**	18.70	19.35	20.30	17.55	**20.10**	20.25	20.25
Project start-up costs	**2.50**	1.45	0.95	1.35	0.65	**1.60**	1.30	1.35
Total cash operating costs [6]	**24.90**	20.15	20.30	21.65	18.20	**21.70**	21.55	21.60
Depreciation, depletion and amortization	**5.90**	4.70	5.05	6.65	5.95	**5.20**	6.20	6.35
Total operating costs [7]	**30.80**	24.85	25.35	28.30	24.15	**26.90**	27.75	27.95

Footnotes and definitions, see page 55.

Quarterly Operating Summary (continued)

(unaudited)

	Three months ended					Nine months ended		Twelve months ended
	Sept 30 2010	June 30 2010	Mar 31 2010	Dec 31 2009	Sept 30 2009	**Sept 30 2010**	Sept 30 2009	Dec 31 2009
NATURAL GAS								
Gross production								
Natural gas [d]								
Continuing operations	**380**	398	419	424	335	**399**	207	262
Discontinued operations	**120**	138	230	250	182	**162**	97	135
Natural gas liquids and crude oil [a]								
Continuing operations	**5.4**	5.5	6.2	6.2	4.8	**5.7**	2.3	3.3
Discontinued operations	**2.2**	2.8	7.8	8.8	5.9	**4.3**	3.4	4.8
Total gross production [f]								
Continuing operations	**412**	431	456	461	363	**433**	221	282
Discontinued operations	**134**	155	277	303	218	**188**	117	164
Average sales price from continuing operations [1]								
Natural gas [g]	**3.66**	3.42	5.34	3.92	2.70	**4.24**	3.43	3.63
Natural gas [g]*	**3.66**	3.42	5.34	3.91	2.68	**4.24**	3.41	3.62
Natural gas liquids and crude oil [b]	**68.03**	82.82	74.71	65.74	58.31	**73.66**	51.89	59.41

Footnotes and definitions, see page 55.

Quarterly Operating Summary (continued)

(unaudited)

	Three months ended					Nine months ended		Twelve months ended
	Sept 30 2010	June 30 2010	Mar 31 2010	Dec 31 2009	Sept 30 2009***	**Sept 30 2010**	Sept 30 2009***	Dec 31 2009***
INTERNATIONAL AND OFFSHORE								
East Coast Canada								
Production [a]								
Terra Nova	**17.2**	27.2	29.6	24.0	16.0	**24.6**	16.0	20.8
Hibernia	**32.3**	30.1	30.2	26.3	28.5	**30.9**	28.5	27.2
White Rose	**16.8**	13.3	14.8	13.3	5.1	**14.9**	5.1	10.0
Total production	**66.3**	70.6	74.6	63.6	49.6	**70.4**	49.6	58.0
Average sales price [1], [b]	**78.78**	76.88	78.69	77.71	75.22	**78.11**	75.22	76.86
International								
Production [e]								
North Sea								
Buzzard	**58.6**	49.3	58.6	59.9	29.4	**55.5**	29.4	47.8
Production from discontinued operations	**25.2**	22.7	27.5	31.1	25.2	**25.2**	25.2	28.7
Total North Sea	**83.8**	72.0	86.1	91.0	54.6	**80.7**	54.6	76.5
Other International								
Libya	**35.4**	35.4	35.4	26.0	42.7	**35.4**	42.7	32.6
Syria*****	**16.5**	12.8	—	—	—	**9.9**	—	—
Production from discontinued operations	**4.2**	11.1	11.7	12.0	11.3	**9.0**	11.3	11.7
Total Other International	**56.1**	59.3	47.1	38.0	54.0	**54.3**	54.0	44.3
Total production	**139.9**	131.3	133.2	129.0	108.6	**135.0**	108.6	120.8
Average sales price from continuing operations [1], [l]								
Buzzard	**75.60**	78.57	72.36	68.71	72.02	**75.35**	72.02	69.53
Other International	**74.90**	76.14	73.40	79.18	75.60	**76.16**	75.60	78.05
Total International and Offshore Production [e]	**206.2**	201.9	207.8	192.6	158.2	**205.4**	158.2	178.8

Footnotes and definitions, see page 55.

Quarterly Operating Summary (continued)

(unaudited)

	Three months ended					Nine months ended		Twelve months ended
	Sept 30 2010	June 30 2010	Mar 31 2010	Dec 31 2009	Sept 30 2009	**Sept 30 2010**	Sept 30 2009	Dec 31 2009
REFINING AND MARKETING								
Eastern North America								
Refined product sales [h]								
Transportation fuels								
Gasoline	**22.5**	22.5	21.0	23.0	18.3	**22.0**	11.7	14.6
Distillate	**11.7**	12.5	12.3	13.9	10.3	**12.2**	7.0	8.8
Total transportation fuel sales	**34.2**	35.0	33.3	36.9	28.6	**34.2**	18.7	23.4
Petrochemicals	**2.5**	2.8	2.2	1.2	1.7	**2.5**	1.2	0.8
Asphalt	**3.7**	3.0	1.8	2.0	2.4	**2.8**	1.3	1.5
Other	**6.0**	6.0	4.3	1.9	3.0	**5.4**	1.6	2.0
Total refined product sales	**46.4**	46.8	41.6	42.0	35.7	**44.9**	22.8	27.7
Crude oil supply and refining								
Processed at refineries [h]	**30.7**	30.6	31.0	28.3	25.5	**30.8**	16.2	29.6
Utilization of refining capacity [j]	**90**	90	91	83	94	**90**	90	87
Western North America								
Refined product sales [h]								
Transportation fuels								
Gasoline	**19.9**	19.2	18.1	18.4	16.1	**19.1**	11.1	13.0
Distillate	**17.4**	16.3	16.9	15.6	11.8	**16.9**	7.4	9.5
Total transportation fuel sales	**37.3**	35.5	35.0	34.0	27.9	**36.0**	18.5	22.5
Asphalt	**1.5**	1.5	1.2	0.9	1.7	**1.4**	1.4	1.3
Other	**3.7**	5.2	4.4	6.0	4.6	**4.5**	2.5	3.4
Total refined product sales	**42.5**	42.2	40.6	40.9	34.2	**41.9**	22.4	27.2
Crude oil supply and refining								
Processed at refineries [h]	**36.6**	31.7	33.5	33.4	27.8	**34.0**	19.3	33.6
Utilization of refining capacity [j]	**101**	87	92	96	100	**94**	101	97

Footnotes and definitions, see page 55.

Quarterly Operating Summary (continued)

(unaudited)

	Three months ended					Nine months ended		Twelve months ended
	Sept 30 2010	June 30 2010	Mar 31 2010	Dec 31 2009	Sept 30 2009	**Sept 30 2010**	Sept 30 2009	Dec 31 2009
NETBACKS – Continuing Operations								
Natural Gas [g]								
Average price realized [8]	**4.76**	5.06	6.23	5.02	3.69	**5.37**	4.12	4.50
Royalties	**(0.50)**	(0.06)	(0.91)	(0.71)	(0.18)	**(0.50)**	(0.10)	(0.37)
Operating costs	**(1.92)**	(2.10)	(1.67)	(1.88)	(1.80)	**(1.90)**	(1.77)	(1.80)
Operating netback	**2.34**	2.90	3.65	2.43	1.71	**2.97**	2.25	2.33
Depreciation, depletion and amortization	**(8.36)**	(4.88)	(3.36)	(2.84)	(3.06)	**(5.64)**	(3.02)	(2.95)
Administrative expenses and other	**0.17**	(0.48)	0.40	(1.67)	(2.34)	**0.21**	(2.07)	(1.91)
Earnings before income taxes	**(5.85)**	(2.46)	0.69	(2.08)	(3.69)	**(2.46)**	(2.84)	(2.53)
International and Offshore								
East Coast Canada [b]								
Average price realized [8]	**81.06**	78.99	80.79	79.69	77.85	**80.28**	77.85	79.07
Royalties	**(25.49)**	(28.45)	(28.78)	(25.26)	(21.02)	**(27.63)**	(21.02)	(23.82)
Operating costs	**(9.08)**	(8.19)	(8.48)	(7.61)	(12.99)	**(8.58)**	(12.99)	(9.45)
Operating netback	**46.49**	42.35	43.53	46.82	43.84	**44.07**	43.84	45.80
Depreciation, depletion and amortization	**(26.44)**	(24.08)	(23.38)	(26.56)	(17.48)	**(24.58)**	(17.48)	(23.47)
Administrative expenses and other	**(1.55)**	0.91	(0.13)	(1.61)	(0.89)	**(0.22)**	(0.89)	(1.36)
Earnings before income taxes	**18.50**	19.18	20.02	18.65	25.47	**19.27**	25.47	20.97
North Sea – Buzzard [b]								
Average price realized [8]	**77.43**	80.35	74.19	70.38	75.49	**77.17**	75.49	71.64
Operating costs	**(4.73)**	(5.35)	(4.92)	(4.57)	(6.29)	**(4.98)**	(6.29)	(4.99)
Operating netback	**72.70**	75.00	69.27	65.81	69.20	**72.19**	69.20	66.65
Depreciation, depletion and amortization	**(23.19)**	(21.83)	(22.76)	(25.24)	(18.54)	**(22.64)**	(18.54)	(23.60)
Administrative expenses and other	**(5.13)**	(3.72)	(3.35)	(2.20)	(2.83)	**(4.09)**	(2.83)	(2.36)
Earnings before income taxes	**44.38**	49.45	43.16	38.37	47.83	**45.46**	47.83	40.69
Other International [l]								
Average price realized [8]	**75.24**	76.61	73.92	79.97	76.02	**76.60**	76.02	78.19
Royalties	**(32.06)**	(36.99)	(43.28)	(32.12)	(46.46)	**(37.91)**	(46.46)	(39.88)
Operating costs	**(5.06)**	(7.87)	(3.81)	(6.03)	(2.21)	**(5.74)**	(2.21)	(4.05)
Operating netback	**38.12**	31.75	26.83	41.82	27.35	**32.95**	27.35	34.26
Depreciation, depletion and amortization	**(4.97)**	(4.64)	(4.29)	(6.39)	(1.54)	**(4.68)**	(1.54)	(3.86)
Administrative expenses and other	**(6.29)**	(5.09)	(6.63)	(11.46)	(5.98)	**(5.95)**	(5.98)	(8.60)
Earnings before income taxes	**26.86**	22.02	15.91	23.97	19.83	**22.32**	19.83	21.80

Footnotes and definitions, see page 55.

Quarterly Operating Summary (continued)

Non-GAAP Financial Measures

Certain financial measures referred to in the Highlights and Quarterly Operating Summary are not prescribed by Canadian generally accepted accounting principles (GAAP). Suncor includes cash flow from operations, return on capital employed and cash and total operating costs per barrel data because investors may use this information to analyze operating performance, leverage and liquidity. The additional information should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP.

Definitions

(1) Average sales price	– This operating statistic is calculated before royalties (where applicable) and net of related transportation costs.
(2) Cash operating costs	– Include cash costs that are defined as operating, selling and general expenses (excluding inventory changes), accretion expense and the cost of bitumen imported from third parties. Per barrel amounts are based on total production volumes. For a reconciliation of this non-GAAP financial measure see Management's Discussion and Analysis.
(3) Total cash operating costs	– Include cash operating costs – Total operations as defined above and cash start-up costs. Per barrel amounts are based on total production volumes.
(4) Total operating costs	– Include total cash operating costs – Total operations as defined above and non-cash operating costs. Per barrel amounts are based on total production volumes.
(5) Cash operating costs – In situ bitumen production	– Include cash costs that are defined as operating, selling and general expenses (excluding inventory changes) and accretion expense. Per barrel amounts are based on in situ production volumes only.
(6) Total cash operating costs – In situ bitumen production	– Include cash operating costs – In situ bitumen production as defined above and cash start-up operating costs. Per barrel amounts are based on in situ production volumes only.
(7) Total operating costs – In situ bitumen production	– Include total cash operating costs – In situ bitumen production as defined above and non-cash operating costs. Per barrel amounts are based on in situ production volumes only.
(8) Average price realized	– This operating statistic is calculated before transportation costs and royalties and excludes the impact of hedging activities.

Explanatory Notes

* Excludes the impact of realized hedging activities.

** If capital employed were to include capitalized costs related to major projects in progress, the return on capital employed would be as stated on this line.

*** For the three and nine months ended September 30, 2009, and the twelve months ended December 31, 2009, operating summary information reflects results of operations since the merger with Petro-Canada on August 1, 2009.

**** Users are cautioned that the Syncrude cash costs per barrel measure may not be fully comparable to similar information calculated by other entities (including Suncor's own cash costs per barrel excluding Syncrude) due to differing treatments for operating and capital costs among producers.

***** Commercial production for Syria commenced on April 19, 2010.

(a) thousands of barrels per day
(b) dollars per barrel
(c) dollars per barrel rounded to the nearest $0.05
(d) millions of cubic feet per day
(e) thousands of barrels of oil equivalent per day
(f) millions of cubic feet equivalent per day
(g) dollars per thousand cubic feet equivalent
(h) thousands of cubic metres per day
(i) $ millions
(j) percentage
(k) thousands of barrels of bitumen per day
(l) dollars per barrel of oil equivalent

Metric conversion

Crude oil, refined products, etc. $1m^3$ (cubic metre) = approx. 6.29 barrels

Consolidated Statements of Earnings

(unaudited)

($ millions)	Three months ended September 30 2010	2009	Nine months ended September 30 2010	2009
Revenues				
Operating revenues	**8 101**	5 651	**23 967**	10 863
Less: Royalties	**(587)**	(440)	**(1 528)**	(586)
Operating revenues (net of royalties)	**7 514**	5 211	**22 439**	10 277
Energy supply and trading activities	**1 119**	2 608	**2 050**	6 896
Interest and other income	**3**	438	**72**	439
	8 636	8 257	**24 561**	17 612
Expenses				
Purchases of crude oil and products	**3 494**	2 284	**10 922**	4 502
Operating, selling and general	**1 882**	1 668	**5 520**	4 188
Energy supply and trading activities	**1 164**	2 572	**1 999**	6 857
Transportation	**165**	122	**471**	246
Depreciation, depletion and amortization (note 5)	**1 070**	523	**2 939**	1 103
Accretion of asset retirement obligations	**44**	38	**132**	94
Exploration	**67**	84	**160**	123
Loss (gain) on disposal of assets	**(105)**	(10)	**(133)**	12
Project start-up costs	**21**	12	**48**	38
Financing expenses (income) (note 7)	**(142)**	(347)	**146**	(416)
	7 660	6 946	**22 204**	16 747
Earnings Before Income Taxes	**976**	1 311	**2 357**	865
Provisions for (Recovery of) Income Taxes (note 8)				
Current	**275**	445	**705**	649
Future	**92**	(99)	**261**	(514)
	367	346	**966**	135
Net earnings from continuing operations	**609**	965	**1 391**	730
Net earnings (loss) from discontinued operations (note 4)	**413**	(36)	**827**	(41)
Net Earnings	**1 022**	929	**2 218**	689
Net Earnings from Continuing Operations per Common Share (dollars)				
Basic	**0.39**	0.72	**0.89**	0.68
Diluted	**0.39**	0.71	**0.88**	0.67
Net Earnings per Common Share (dollars), (note 9)				
Basic	**0.65**	0.69	**1.42**	0.64
Diluted	**0.65**	0.68	**1.41**	0.63
Cash dividends	**0.10**	0.10	**0.30**	0.20

Consolidated Statements of Comprehensive Income

(unaudited)

($ millions)	Three months ended September 30 2010	2009	Nine months ended September 30 2010	2009
Net earnings	**1 022**	929	**2 218**	689
Other comprehensive income (loss), net of tax				
Change in foreign currency translation adjustment	**168**	(186)	**(268)**	(250)
Reclassification to net earnings	**44**	—	**44**	—
Gain on derivative contracts designated as cash flow hedges	**—**	1	**—**	1
Reclassification to net earnings	**(1)**	—	**(1)**	2
Comprehensive Income	**1 233**	744	**1 993**	442

Consolidated Balance Sheets

(unaudited)

($ millions)	**September 30 2010**	December 31 2009
Assets		
Current assets		
Cash and cash equivalents	**598**	505
Accounts receivable	**4 051**	3 703
Inventories	**3 100**	2 947
Income taxes receivable	**718**	587
Future income taxes	**359**	332
Assets of discontinued operations (note 4)	**137**	257
Total current assets	**8 963**	8 331
Property, plant and equipment, net	**54 853**	54 198
Other assets	**448**	491
Goodwill	**3 201**	3 201
Future income taxes	**53**	193
Assets of discontinued operations (note 4)	**950**	3 332
Total assets	**68 468**	69 746
Liabilities and Shareholders' Equity		
Current liabilities		
Short-term debt	**2**	2
Current portion of long-term debt (note 13)	**518**	25
Accounts payable and accrued liabilities	**6 416**	6 307
Income taxes payable	**819**	1 254
Future income taxes	**22**	18
Liabilities of discontinued operations (note 4)	**55**	242
Total current liabilities	**7 832**	7 848
Long-term debt (note 13)	**11 534**	13 855
Accrued liabilities and other	**4 222**	4 372
Future income taxes	**8 571**	8 367
Liabilities of discontinued operations (note 4)	**581**	1 193
Shareholders' equity	**35 728**	34 111
Total liabilities and shareholders' equity	**68 468**	69 746

Shareholders' Equity

	Number (thousands)		Number (thousands)	
Share capital	**1 562 822**	**20 120**	1 559 778	20 053
Contributed surplus		**551**		526
Accumulated other comprehensive income (loss) (note 15)		**(458)**		(233)
Retained earnings		**15 515**		13 765
Total shareholders' equity		**35 728**		34 111

Consolidated Statements of Cash Flows

(unaudited)

($ millions)	Three months ended September 30 **2010**	2009	Nine months ended September 30 **2010**	2009
Operating Activities				
Net earnings from continuing operations	**609**	965	**1 391**	730
Adjustments for:				
Depreciation, depletion and amortization	**1 070**	523	**2 939**	1 103
Future income taxes	**92**	(99)	**261**	(514)
Accretion of asset retirement obligations	**44**	38	**132**	94
Unrealized foreign exchange gain on U.S. dollar denominated long-term debt (note 7)	**(252)**	(400)	**(136)**	(657)
Change in fair value of derivative contracts (note 6)	**—**	(333)	**(253)**	1 039
Loss (gain) on disposal of assets	**(105)**	(10)	**(133)**	12
Stock-based compensation	**80**	125	**—**	228
Gain on effective settlement of pre-existing contract with Petro-Canada	**—**	(438)	**—**	(438)
Other	**(93)**	61	**(241)**	(127)
Exploration expenses	**40**	52	**74**	83
Decrease (increase) in non-cash working capital related to operating activities (note 10)	**21**	(22)	**(751)**	(679)
Cash flow provided by continuing operations	**1 506**	462	**3 283**	874
Cash flow provided by discontinued operations	**138**	211	**459**	228
Cash flow provided by operating activities	**1 644**	673	**3 742**	1 102
Investing Activities				
Capital and exploration expenditures	**(1 443)**	(888)	**(3 966)**	(2 590)
Other investments	**(16)**	25	**(19)**	(6)
Proceeds from disposal of assets	**143**	9	**265**	36
Cash acquired through business combination	**—**	248	**—**	248
Increase in non-cash working capital related to investing activities	**(109)**	(30)	**(250)**	(708)
Cash flow used in continuing investing activities	**(1 425)**	(636)	**(3 970)**	(3 020)
Cash flow provided by (used in) discontinued investing activities	**1 390**	(81)	**2 409**	(121)
Cash flow used in investing activities	**(35)**	(717)	**(1 561)**	(3 141)
Financing Activities				
Increase in short-term debt	**—**	—	**—**	1
Net increase (decrease) in revolving-term debt	**(1 318)**	311	**(1 672)**	2 209
Issuance of common shares under stock option plan	**12**	8	**47**	30
Dividends paid on common shares	**(155)**	(155)	**(462)**	(249)
Cash flow provided by (used in) financing activities	**(1 461)**	164	**(2 087)**	1 991
Increase (Decrease) in Cash and Cash Equivalents	**148**	120	**94**	(48)
Effect of Foreign Exchange on Cash and Cash Equivalents	**(5)**	(18)	**(1)**	(25)
Cash and Cash Equivalents at Beginning of Period	**455**	485	**505**	660
Cash and Cash Equivalents at End of Period	**598**	587	**598**	587

Consolidated Statements of Changes in Shareholders' Equity

(unaudited)

($ millions)	Share Capital	Contributed Surplus	Accumulated Other Comprehensive Income (Loss)	Retained Earnings
At December 31, 2008	1 113	288	97	13 025
Net earnings	—	—	—	689
Dividends paid on common shares	—	—	—	(249)
Issued for cash under stock option plan	38	(8)	—	—
Issued under dividend reinvestment plan	2	—	—	—
Stock-based compensation expense	—	77	—	—
Issued for Petro-Canada acquisition (note 2)	18 878	—	—	—
Fair value of Petro-Canada stock options exchanged for Suncor stock options	—	147	—	—
Income tax benefit of stock option deduction in the U.S.	—	4	—	—
Change in accumulated other comprehensive income (loss)	—	—	(247)	—
At September 30, 2009	20 031	508	(150)	13 465
At December 31, 2009	20 053	526	(233)	13 765
Net earnings	**—**	**—**	**—**	**2 218**
Dividends paid on common shares	**—**	**—**	**—**	**(462)**
Issued for cash under stock option plans	**61**	**(14)**	**—**	**—**
Issued under dividend reinvestment plan	**6**	**—**	**—**	**(6)**
Stock-based compensation expense	**—**	**39**	**—**	**—**
Change in accumulated other comprehensive income (loss)	**—**	**—**	**(225)**	**—**
At September 30, 2010	**20 120**	**551**	**(458)**	**15 515**

Schedules of Segmented Data from Continuing Operations

(unaudited)

									Three months ended September 30			
	Oil Sands		Natural Gas		International and Offshore		Refining and Marketing		Corporate, Energy Trading and Eliminations		Total	
($ millions)	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009
EARNINGS												
Revenues												
Operating revenues	**1 728**	1 190	**161**	90	**1 063**	474	**5 139**	3 850	**10**	47	**8 101**	5 651
Less: Royalties	**(290)**	(219)	**(19)**	(6)	**(278)**	(215)	**—**	—	**—**	—	**(587)**	(440)
Operating revenues (net of royalties)	**1 438**	971	**142**	84	**785**	259	**5 139**	3 850	**10**	47	**7 514**	5 211
Energy supply and trading activities	**—**	—	**—**	—	**—**	—	**—**	—	**1 119**	2 608	**1 119**	2 608
Intersegment revenues	**709**	987	**19**	32	**173**	97	**55**	2	**(956)**	(1 118)	**—**	—
Interest and other income	**115**	438	**—**	—	**—**	—	**—**	—	**(112)**	—	**3**	438
	2 262	2 396	**161**	116	**958**	356	**5 194**	3 852	**61**	1 537	**8 636**	8 257
Expenses												
Purchases of crude oil and products	**226**	16	**—**	—	**—**	16	**4 270**	3 258	**(1 002)**	(1 006)	**3 494**	2 284
Operating, selling and general	**1 060**	981	**89**	79	**111**	39	**553**	409	**69**	160	**1 882**	1 668
Energy supply and trading activities	**—**	—	**—**	—	**—**	—	**—**	—	**1 164**	2 572	**1 164**	2 572
Transportation	**63**	62	**44**	14	**16**	15	**50**	35	**(8)**	(4)	**165**	122
Depreciation, depletion and amortization	**298**	242	**330**	97	**307**	81	**120**	96	**15**	7	**1 070**	523
Accretion of asset retirement obligations	**30**	30	**7**	5	**7**	3	**—**	—	**—**	—	**44**	38
Exploration	**1**	2	**2**	50	**64**	32	**—**	—	**—**	—	**67**	84
Gain on disposal of assets	**—**	—	**(89)**	(5)	**—**	—	**(16)**	(5)	**—**	—	**(105)**	(10)
Project start-up costs	**21**	12	**—**	—	**—**	—	**—**	—	**—**	—	**21**	12
Financing expenses (income)	**4**	—	**1**	—	**4**	1	**3**	—	**(154)**	(348)	**(142)**	(347)
	1 703	1 345	**384**	240	**509**	187	**4 980**	3 793	**84**	1 381	**7 660**	6 946
Earnings (loss) before income taxes	**559**	1 051	**(223)**	(124)	**449**	169	**214**	59	**(23)**	156	**976**	1 311
Income taxes	**(147)**	(313)	**56**	27	**(213)**	(76)	**(62)**	(14)	**(1)**	30	**(367)**	(346)
Net earnings (loss) from continuing operations	**412**	738	**(167)**	(97)	**236**	93	**152**	45	**(24)**	186	**609**	965
CAPITAL AND EXPLORATION EXPENDITURES – continuing operations	**(962)**	(603)	**(43)**	(39)	**(175)**	(154)	**(152)**	(88)	**(111)**	(4)	**(1 443)**	(888)

Schedules of Segmented Data from Continuing Operations (continued)

(unaudited)

									Nine months ended September 30			
	Oil Sands		Natural Gas		International and Offshore		Refining and Marketing		Corporate, Energy Trading and Eliminations		Total	
($ millions)	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009
EARNINGS												
Revenues												
Operating revenues	**5 094**	2 953	**547**	194	**3 283**	474	**14 991**	7 106	**52**	136	**23 967**	10 863
Less: Royalties	**(542)**	(365)	**(58)**	(6)	**(928)**	(215)	**—**	—	**—**	—	**(1 528)**	(586)
Operating revenues (net of royalties)	**4 552**	2 588	**489**	188	**2 355**	259	**14 991**	7 106	**52**	136	**22 439**	10 277
Energy supply and trading activities	**—**	—	**—**	—	**—**	—	**—**	—	**2 050**	6 896	**2 050**	6 896
Intersegment revenues	**1 877**	1 527	**87**	54	**467**	97	**206**	2	**(2 637)**	(1 680)	**—**	—
Interest and other income	**305**	438	**—**	—	**—**	—	**39**	—	**(272)**	1	**72**	439
	6 734	4 553	**576**	242	**2 822**	356	**15 236**	7 108	**(807)**	5 353	**24 561**	17 612
Expenses												
Purchases of crude oil and products	**728**	242	**—**	—	**163**	16	**12 545**	5 718	**(2 514)**	(1 474)	**10 922**	4 502
Operating, selling and general	**3 274**	2 977	**234**	146	**281**	39	**1 605**	754	**126**	272	**5 520**	4 188
Energy supply and trading activities	**—**	—	**—**	—	**—**	—	**—**	—	**1 999**	6 857	**1 999**	6 857
Transportation	**203**	178	**82**	22	**67**	15	**143**	44	**(24)**	(13)	**471**	246
Depreciation, depletion and amortization	**1 021**	622	**647**	174	**870**	81	**352**	203	**49**	23	**2 939**	1 103
Accretion of asset retirement obligations	**90**	82	**20**	8	**20**	3	**2**	1	**—**	—	**132**	94
Exploration	**6**	8	**13**	83	**141**	32	**—**	—	**—**	—	**160**	123
Loss (gain) on disposal of assets	**11**	17	**(126)**	(20)	**—**	—	**(19)**	15	**1**	—	**(133)**	12
Project start-up costs	**45**	38	**—**	—	**3**	—	**—**	—	**—**	—	**48**	38
Financing expenses (income)	**4**	—	**(3)**	—	**(28)**	1	**2**	—	**171**	(417)	**146**	(416)
	5 382	4 164	**867**	413	**1 517**	187	**14 630**	6 735	**(192)**	5 248	**22 204**	16 747
Earnings (loss) before income taxes	**1 352**	389	**(291)**	(171)	**1 305**	169	**606**	373	**(615)**	105	**2 357**	865
Income taxes	**(347)**	(68)	**79**	41	**(643)**	(76)	**(177)**	(117)	**122**	85	**(966)**	(135)
Net earnings (loss) from continuing operations	**1 005**	321	**(212)**	(130)	**662**	93	**429**	256	**(493)**	190	**1 391**	730
CAPITAL AND EXPLORATION EXPENDITURES – continuing operations	**(2 642)**	(2 097)	**(113)**	(189)	**(608)**	(154)	**(395)**	(141)	**(208)**	(9)	**(3 966)**	(2 590)

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

1. ACCOUNTING POLICIES

These interim consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles and follow the same accounting policies and methods of computation as, and should be read in conjunction with, the most recent annual financial statements. Certain information and disclosures normally required to be included in notes to the annual consolidated financial statements have been condensed or omitted.

In the opinion of management, these interim consolidated financial statements contain all adjustments of a normal and recurring nature necessary to present fairly Suncor Energy Inc.'s (Suncor) financial position at September 30, 2010 and the results of its operations and cash flows for the three and nine month periods ended September 30, 2010 and 2009.

Certain prior period comparative figures have been reclassified to conform to the current period presentation.

2. BUSINESS COMBINATION WITH PETRO-CANADA

(a) Overview

On August 1, 2009, Suncor completed its merger with Petro-Canada. The company has accounted for this business combination as prescribed by Canadian Institute of Chartered Accountants (CICA) Handbook section 1581 "Business Combinations." As the acquirer, the company is required to recognize Petro-Canada assets and liabilities as at August 1, 2009. The results of Petro-Canada operations are included in the consolidated financial statements of the company from August 1, 2009.

(b) Final Allocation of Purchase Price

The following estimated fair values were assigned to the net assets of Petro-Canada as at August 1, 2009:

($ millions)	
Current assets	4 645
Property, plant and equipment	27 407
Other assets	537
Total assets	32 589
Current liabilities	3 741
Long-term debt	4 410
Accrued liabilities and other	3 416
Future income taxes	4 570
Total liabilities	16 137
Net assets purchased	16 452
Goodwill	3 178
Total purchase price	19 630

The purchase price allocation was based on best estimates by Suncor's management and was based principally on valuations prepared by independent valuation specialists. Management finalized the purchase price allocation during the second quarter of 2010 and did not make any amendments to the preliminary allocation.

3. CHANGE IN SEGMENTED DISCLOSURES

During the first quarter of 2010, as a result of planned divestitures of the company's assets in Trinidad and Tobago, The Netherlands and certain assets in the United Kingdom (U.K.) (described in note 4), the company combined its International and East Coast Canada segments into one new segment, International and Offshore. Continuing operations for the International and Offshore segment are comprised of activity offshore Newfoundland and Labrador, including interests in the Hibernia, Terra Nova, White Rose and Hebron oilfields, and the exploration for, and production of, crude oil and natural gas in the U.K., Norway, Libya and Syria.

All prior periods have been restated to conform to these segment definitions.

4. DISCONTINUED OPERATIONS

The company is divesting certain non-core assets as part of its continuing strategic alignment.

Natural Gas

On August 31, 2010, the company completed the sale of non-core natural gas properties located in west central Alberta (Bearberry and Ricinus) for net proceeds of $275 million.

On September 30, 2010, the company completed the sale of non-core assets in southern Alberta (Wildcat Hills) for net proceeds of $351 million.

In the first quarter of 2010, the company completed the sale of its oil and gas producing assets in the U.S. Rockies for net proceeds of US$481 million (Cdn$502 million). In the second quarter of 2010, the company completed the sale of non-core natural gas properties located in northeast British Columbia (Blueberry and Jedney) for net proceeds of $383 million, and non-core assets in central Alberta (Rosevear and Pine Creek) for net proceeds of $229 million.

International and Offshore

On August 5, 2010, the company completed the Trinidad and Tobago asset sale for net proceeds of US$378 million (Cdn$383 million).

On August 13, 2010, the company completed the sale of its shares in Petro-Canada Netherlands BV for net proceeds of €316 million (Cdn$420 million).

On September 8, 2010, the company reached an agreement to sell non-core U.K. offshore assets (Scott/Telford and Triton) for gross proceeds of £240 million. The sale is expected to close during the first quarter of 2011 and is subject to closing conditions and regulatory approvals typical of transactions of this nature.

Net income from discontinued operations reported in the Consolidated Statements of Earnings is as follows:

	Three months ended September 30					
	Natural Gas		**International and Offshore**		**Total**	
($ millions)	**2010**	2009	**2010**	2009	**2010**	2009
Revenues						
Operating revenues[1]	**53**	86	**174**	119	**227**	205
Less: Royalties	**(8)**	(10)	**—**	—	**(8)**	(10)
Operating revenues (net of royalties)	**45**	76	**174**	119	**219**	195
Gain on disposal of assets	**271**	—	**169**	—	**440**	—
	316	76	**343**	119	**659**	195
Expenses						
Operating, selling and general	**14**	35	**16**	53	**30**	88
Transportation	**9**	6	**4**	5	**13**	11
Depreciation, depletion and amortization	**27**	51	**110**	47	**137**	98
Accretion of asset retirement obligations	**2**	2	**4**	5	**6**	7
Exploration	**1**	—	**11**	45	**12**	45
Financing expenses (income)	**—**	—	**3**	(1)	**3**	(1)
	53	94	**148**	154	**201**	248
Earnings before income taxes	**263**	(18)	**195**	(35)	**458**	(53)
Income taxes	**66**	(4)	**(21)**	(13)	**45**	(17)
Net earnings	**197**	(14)	**216**	(22)	**413**	(36)

(1) Operating revenues reported in Natural Gas include sales to other operating segments that would be eliminated upon consolidation in the Consolidated Statements of Earnings. These totalled $8 million in the three months ended September 30, 2010 (2009 – $9 million).

	Three months ended September 30	
(dollars)	**2010**	2009
Basic earnings per share from discontinued operations	**0.26**	(0.03)
Diluted earnings per share from discontinued operations	**0.26**	(0.03)

	Natural Gas		International and Offshore		Total	
					Nine months ended September 30	
($ millions)	**2010**	2009	**2010**	2009	**2010**	2009
Revenues						
Operating revenues[1]	**277**	148	**546**	119	**823**	267
Less: Royalties	**(41)**	(26)	**—**	—	**(41)**	(26)
Operating revenues (net of royalties)	**236**	122	**546**	119	**782**	241
Gain on disposal of assets	**646**	—	**169**	—	**815**	—
	882	122	**715**	119	**1 597**	241
Expenses						
Operating, selling and general	**64**	51	**88**	53	**152**	104
Transportation	**24**	9	**18**	5	**42**	14
Depreciation, depletion and amortization	**95**	84	**169**	47	**264**	131
Accretion of asset retirement obligations	**8**	4	**15**	5	**23**	9
Exploration	**1**	—	**16**	45	**17**	45
Financing expenses (income)	**7**	—	**11**	(1)	**18**	(1)
	199	148	**317**	154	**516**	302
Earnings before income taxes	**683**	(26)	**398**	(35)	**1 081**	(61)
Income taxes	**175**	(7)	**79**	(13)	**254**	(20)
Net earnings	**508**	(19)	**319**	(22)	**827**	(41)

(1) Operating revenues reported in Natural Gas include sales to other operating segments that would be eliminated upon consolidation in the Consolidated Statements of Earnings. These totalled $62 million in the nine months ended September 30, 2010 (2009 — $9 million).

	Nine months ended September 30	
(dollars)	**2010**	2009
Basic earnings per share from discontinued operations	**0.53**	(0.04)
Diluted earnings per share from discontinued operations	**0.53**	(0.04)

The assets and liabilities of discontinued operations presented on the Consolidated Balance Sheets are as follows:

	Natural Gas		International and Offshore		Total	
	September 30	December 31	**September 30**	December 31	**September 30**	December 31
($ millions)	**2010**	2009	**2010**	2009	**2010**	2009
Assets						
Current assets	**7**	34	**130**	223	**137**	257
Property, plant and equipment, net	**202**	1 600	**748**	1 732	**950**	3 332
Total assets	**209**	1 634	**878**	1 955	**1 087**	3 589
Liabilities						
Current liabilities	**5**	64	**50**	178	**55**	242
Accrued liabilities and other	**74**	286	**256**	404	**330**	690
Future income taxes	**—**	31	**251**	472	**251**	503
Total liabilities	**79**	381	**557**	1 054	**636**	1 435

5. ASSET WRITE-DOWNS

During the third quarter of 2010, the company recognized a write-down of $106 million related to certain North Sea assets in the International and Offshore operating segment. An agreement to sell these assets was entered into during the quarter and the assets were written down to reflect fair value less cost to sell.

During the third quarter of 2010, the company recognized a charge of $222 million to reflect the write-down of certain assets in the Natural Gas operating segment to reflect fair value based on discounted future cash flows.

During the second quarter of 2010, the company recognized a write-down of $189 million related to certain extraction equipment in the Oil Sands operating segment. Also during the second quarter of 2010, the company recognized a charge of $44 million in the Natural Gas operating segment to reflect the write-down of certain Western Canada and Alaska land leases.

These charges are included in depreciation, depletion and amortization expenses and net earnings from discontinued operations in the Consolidated Statements of Earnings.

6. FINANCIAL INSTRUMENTS AND FINANCIAL RISK FACTORS

Derivatives are financial instruments that either imitate or counter the price movements of stocks, bonds, currencies, commodities and interest rates. Suncor uses derivatives to reduce its exposure to fluctuations in commodity prices and foreign currency exchange rates and to manage interest rate or currency-sensitive assets and liabilities. Suncor also uses derivatives for trading purposes. When used in a trading activity, the company is attempting to realize a gain on the fluctuations in the market value of the derivative.

Hedge accounting is a method for recognizing the gains, losses, revenues and expenses associated with the items in a hedging relationship at the time when the underlying transaction impacts earnings. Suncor elects to use hedge accounting on certain derivatives linked to future commodity and financial transactions.

Physical trading commodity contracts that exceed the company's expected purchase, sale or usage requirements are accounted for as derivative financial instruments whereby realized and unrealized gains and losses, and the underlying settlement of these contracts is recognized and reported on a net basis in Energy Supply and Trading Activities revenue. The related inventory is carried at fair value less costs to sell, with changes in fair value recognized as gains or losses within Energy Supply and Trading Activities revenue.

(a) Balance Sheet Financial Instruments

The company's financial instruments in the Consolidated Balance Sheets consist of cash and cash equivalents, accounts receivable, derivative contracts, substantially all current liabilities, long-term debt, and a portion of non-current accrued liabilities and other. Unless otherwise noted, carrying values reflect the current fair value of the company's financial instruments.

The estimated fair values of recognized financial instruments have been determined based on the company's assessment of available market information and appropriate valuation methodologies based on industry accepted third-party models; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction. The company characterizes inputs used in determining fair value using a hierarchy that prioritizes inputs depending on the degree to which they are observable in the market (see page 77 of Suncor's 2009 Annual Report for further detail). As at September 30, 2010, there were no significant changes to the distribution of the fair value hierarchy used to value financial instruments.

The company's fixed-term debt is accounted for under the amortized cost method, with the exception of the portion of debt where future interest payments have been swapped from fixed to floating payments, which is accounted for at fair value. Upon initial recognition, the cost of the debt is its fair value, adjusted for any associated transaction costs. The company does not recognize gains or losses arising from changes in the fair value of this debt until the gains or losses are realized. Gains or losses on

our U.S. dollar denominated long-term debt resulting from changes in the exchange rate are recognized in the period in which they occur. At September 30, 2010, the carrying value of the fixed-term debt accounted for under the amortized cost method was $10.0 billion (December 31, 2009 – $10.1 billion) and the fair value was $11.4 billion (December 31, 2009 – $10.7 billion).

(b) Hedge Accounting

Fair Value Hedges

At September 30, 2010, the company had interest rate swaps classified as fair value hedges outstanding until August 2011, relating to fixed-rate debt. The fair value of these swaps totalled $8 million at September 30, 2010 (December 31, 2009 – $18 million), and was recorded in accounts receivable in the Consolidated Balance Sheets. There was no ineffectiveness recognized on these interest rate swaps during the three and nine month periods ended September 30, 2010 and September 30, 2009.

Cash Flow Hedges

At September 30, 2010, the company had no outstanding cash flow hedges in place (December 31, 2009 – nil).

(c) Other Derivatives

Risk Management Derivatives

The company periodically enters into derivative contracts which although not accounted for as hedges because they have not been documented as such, or do not qualify under GAAP, are believed to be economically effective at mitigating exposure to commodity price movements and are an important component of Suncor's overall risk management program. The earnings impact associated with these contracts for the three month period ended September 30, 2010, was a loss of $11 million, net of income taxes of $3 million (2009 – a gain of $43 million, net of income taxes of $15 million). During the nine month period ended September 30, 2010, the earnings impact was a gain of $70 million, net of income taxes of $24 million (2009 – loss of $658 million, net of income taxes of $232 million).

Significant contracts outstanding at September 30, 2010 were as follows:

Crude oil	Quantity (bpd)	Average Price[1] (US$/bbl)	Period
Purchased puts	55 000	60.00	2010
Sold puts	54 609	60.00	2010
Collars – floor	49 674	50.00	2010
Collars – cap	49 978	68.06	2010

(1) Average price for crude oil derivative contracts is US$ WTI per barrel at Cushing, Oklahoma.

Energy Trading Derivatives

The company's Energy Trading group also uses physical and financial energy contracts, including swaps, forwards and options to earn trading revenues. These energy contracts are comprised of crude oil, natural gas and refined products contracts.

The earnings impact associated with these contracts for the three month period ended September 30, 2010, was a loss of $6 million, net of income taxes of $2 million (2009 – a loss of $1 million, net of income taxes of less than $1 million). During the nine month period ended September 30, 2010, the earnings impact was a gain of $44 million, net of income taxes of $18 million (2009 – loss of $37 million, net of income taxes of $16 million).

Change in Fair Value of Other Derivatives

($ millions)	Risk Management	Energy Trading	Total
Fair value of contracts at December 31, 2009	(312)	(47)	(359)
Fair value of contracts realized during the period	**157**	**(60)**	**97**
Changes in fair value attributable to market price and other market changes during the period	**94**	**62**	**156**
Fair value of contracts outstanding at September 30, 2010 [(a), (b)]	**(61)**	**(45)**	**(106)**

(a) As at September 30, 2010, of the total unrealized derivatives, $98 million is recorded in accounts receivable (December 31, 2009 – $213 million) in the Consolidated Balance Sheets.

(b) As at September 30, 2010, of the total unrealized derivatives, $204 million is recorded in accounts payable and accrued liabilities (December 31, 2009 – $572 million) in the Consolidated Balance Sheets.

Financial Risk Factors

The company is exposed to a number of different financial risks arising from normal course business exposures, as well as the company's use of financial instruments. These risk factors include market risks relating to commodity prices, foreign currency risk and interest rate risk, as well as liquidity risk and credit risk.

The company maintains a formal governance process to manage its financial risks. The company's Risk Management Committee (RMC) is charged with the oversight of the company's risk management for trading activities, which are defined as strategic hedging, optimization trading, marketing and speculative trading. The RMC, acting under board authority, meets regularly to monitor limits on risk exposures, review policy compliance and validate risk-related methodologies and procedures. All risk management activity is carried out by specialist teams that have the appropriate skills, experience and supervision with the appropriate financial and management controls.

At September 30, 2010, the company's exposure to risks arising from the use of financial instruments had not changed significantly from December 31, 2009.

7. FINANCING EXPENSES (INCOME)

	Three months ended September 30		Nine months ended September 30	
($ millions)	**2010**	2009	**2010**	2009
Interest on debt	**170**	156	**521**	391
Capitalized interest	**(65)**	(22)	**(203)**	(94)
Interest expense	**105**	134	**318**	297
Unrealized foreign exchange gain on U.S. dollar denominated long-term debt	**(252)**	(400)	**(136)**	(657)
Foreign exchange gains and other	**5**	(81)	**(36)**	(56)
Total financing expenses (income) from continuing operations [(1)]	**(142)**	(347)	**146**	(416)

(1) For the three months ended September 30, 2010, financing expense of $3 million (2009 – financing income of $1 million) has been reclassified to net earnings from discontinued operations. For the nine months ended September 30, 2010, financing expense of $18 million (2009 – financing income of $1 million) has been reclassified to net earnings from discontinued operations.

8. INCOME TAXES

($ millions)	Three months ended September 30 **2010**	2009	Nine months ended September 30 **2010**	2009
Provision for (recovery of) income taxes:				
Current:				
Canada	**34**	380	**56**	573
Foreign	**241**	65	**649**	76
Future:				
Canada	**91**	(84)	**295**	(539)
Foreign	**1**	(15)	**(34)**	25
Total provision for income taxes from continuing operations [(1)]	**367**	346	**966**	135

(1) For the three months ended September 30, 2010, income tax expense of $45 million (2009 – income tax recovery of $17 million) has been reclassified to net earnings from discontinued operations. For the nine months ended September 30, 2010, income tax expense of $254 million (2009 – income tax recovery of $20 million) has been reclassified to net earnings from discontinued operations

The merger of Suncor Energy Inc. and Petro-Canada resulted in a deemed year end for income tax purposes for both companies effective July 31, 2009. This deemed year end generated an increase in income taxes payable as well as an acceleration of the tax payments. The tax payments that would ordinarily have been payable in monthly installments over the August to December period were due and payable at September 30, 2009.

In the third quarter of 2009, the provision for future income tax increased by $152 million due in part to the merger. The combined provincial allocation of both entities caused an increase to the future income tax rate, the impact of which is recorded in net earnings.

9. RECONCILIATION OF BASIC AND DILUTED EARNINGS PER COMMON SHARE

($ millions)	Three months ended September 30 **2010**	2009	Nine months ended September 30 **2010**	2009
Net earnings	**1 022**	929	**2 218**	689
(millions of common shares)				
Weighted-average number of common shares	**1 563**	1 349	**1 562**	1 076
Dilutive securities:				
Options issued under stock-based compensation plans	**11**	13	**12**	13
Weighted-average number of diluted common shares	**1 574**	1 362	**1 574**	1 089
(dollars per common share)				
Basic earnings per share [(a)]	**0.65**	0.69	**1.42**	0.64
Diluted earnings per share [(b)]	**0.65**	0.68	**1.41**	0.63

Note: An option will have a dilutive effect under the treasury stock method only when the average market price of the common stock during the period exceeds the exercise price of the option.

(a) Basic earnings per share is net earnings divided by the weighted-average number of common shares.

(b) Diluted earnings per share is net earnings divided by the weighted-average number of diluted common shares.

10. CHANGES IN NON-CASH WORKING CAPITAL

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

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

	Three months ended September 30		Nine months ended September 30	
($ millions)	**2010**	2009	**2010**	2009
Operating activities				
Accounts receivable	**864**	313	**126**	(47)
Inventories	**(277)**	5	**(160)**	(376)
Accounts payable and accrued liabilities	**134**	(546)	**(184)**	(221)
Taxes payable/receivable	**(700)**	206	**(533)**	(35)
	21	(22)	**(751)**	(679)

(1) Balances do not include amounts acquired from Petro-Canada as a result of the merger, but do reflect the changes in these working capital accounts subsequent to August 1, 2009.

11. EMPLOYEE FUTURE BENEFITS LIABILITY

The following is the net periodic benefit cost for the three and nine month periods ended September 30:

			Pension Benefits	
	Three months ended September 30		Nine months ended September 30	
($ millions)	**2010**	2009	**2010**	2009
Current service costs	**21**	19	**64**	49
Interest costs	**42**	31	**126**	57
Expected return on plan assets	**(36)**	(24)	**(107)**	(44)
Amortization of net actuarial loss	**2**	5	**6**	15
Net periodic benefit cost	**29**	31	**89**	77

			Other Post-Retirement Benefits	
	Three months ended September 30		Nine months ended September 30	
($ millions)	**2010**	2009	**2010**	2009
Current service costs	**2**	2	**6**	5
Interest costs	**7**	4	**19**	9
Net periodic benefit cost	**9**	6	**25**	14

12. SHARE CAPITAL

Issued

	Common Shares	
	Number (thousands)	Amount ($ millions)
Balance as at December 31, 2009	1 559 778	20 053
Issued for cash under stock option plans	**2 847**	**61**
Issued under dividend reinvestment plan	**197**	**6**
Balance as at September 30, 2010	**1 562 822**	**20 120**

Stock-Based Compensation

(a) Stock Option Plans

(i) Discontinued Plans

There are a number of legacy Suncor and legacy Petro-Canada plans that were in place prior to the merger on August 1, 2009, for which granting of options ended on July 31, 2009. For details of the terms and conditions of these plans, refer to pages 88 and 89 of Suncor's 2009 Annual Report.

(ii) Suncor Energy Inc. Stock Options

This plan replaced the pre-merger stock option plans of legacy Suncor and legacy Petro-Canada. Outstanding options that are cancelled, expire or otherwise result in no underlying common share being issued, will be available for issuance as options under this plan. These options have a seven-year life and vest annually over a three-year period.

Options granted under this plan before August 1, 2010 included a tandem stock appreciation right. The company granted 15,000 options with tandem stock appreciation rights during the third quarter of 2010. Effective August 1, 2010, options granted under this plan no longer include tandem stock appreciation rights. The company granted 21,000 options with no tandem stock appreciation rights after August 1, 2010.

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

	Number (thousands)	Weighted-Average Exercise Price ($)
Outstanding, December 31, 2009	72 024	32.52
Granted	**4 296**	**31.86**
Exercised	**(2 847)**	**14.91**
Forfeited/expired	**(2 710)**	**42.47**
Outstanding, September 30, 2010	**70 763**	**32.50**

(b) Stock Appreciation Rights (SARs)

(i) Discontinued Plan

Legacy Petro-Canada had a SARs plan for which grants ended on July 31, 2009. For details of the terms and conditions of this plan, refer to page 90 of Suncor's 2009 Annual Report.

(ii) Suncor Energy Inc. Stock Appreciation Rights

The company granted 7,000 SARs under this new plan during the third quarter of 2010. These SARs have a seven-year life and vest annually over a three-year period.

Changes in the number of outstanding SARs were as follows:

	Number (thousands)	Weighted-Average Exercise Price ($)
Outstanding, December 31, 2009	14 065	28.63
Granted	**353**	**31.85**
Exercised	**(458)**	**21.30**
Forfeited/expired	**(1 787)**	**28.75**
Outstanding, September 30, 2010	**12 173**	**28.99**

(c) Share Unit Plans

For details of the terms and conditions of the Performance Share Unit (PSU), Restricted Share Unit (RSU) and Deferred Share Unit (DSU) plans, refer to page 91 of Suncor's 2009 Annual Report.

Changes in the number of outstanding units were as follows:

	Number (thousands)		
	PSU	RSU	DSU
Outstanding, December 31, 2009	3 247	4 250	2 616
Granted	**1 672**	**2 835**	**36**
Redeemed	**(282)**	**(101)**	**(211)**
Forfeited	**(803)**	**(417)**	**—**
Reinvested	**21**	**34**	**22**
Outstanding, September 30, 2010	**3 855**	**6 601**	**2 463**

Stock-Based Compensation Expense (Recovery)

The following table summarizes the stock-based compensation expense (recovery) recorded for all plans within operating, selling and general expense on the Consolidated Statements of Earnings:

	Three months ended September 30		Nine months ended September 30	
($ millions)	**2010**	2009	**2010**	2009
Stock option plans	**35**	65	**20**	116
SARs	**10**	25	**(12)**	25
PSUs	**14**	9	**7**	19
RSUs	**22**	32	**57**	57
DSUs	**8**	7	**(7)**	30
Total stock-based compensation expense	**89**	138	**65**	247

13. LONG-TERM DEBT AND CREDIT FACILITIES

($ millions)	**September 30 2010**	December 31 2009
Fixed-term debt, redeemable at the option of the company		
6.85% Notes, denominated in U.S. dollars, due in 2039 (US$750)	**772**	785
6.80% Notes, denominated in U.S. dollars, due in 2038 (US$900)	**956**	972
6.50% Notes, denominated in U.S. dollars, due in 2038 (US$1150)	**1 185**	1 204
5.95% Notes, denominated in U.S. dollars, due in 2035 (US$600)	**571**	578
5.95% Notes, denominated in U.S. dollars, due in 2034 (US$500)	**515**	523
5.35% Notes, denominated in U.S. dollars, due in 2033 (US$300)	**264**	266
7.15% Notes, denominated in U.S. dollars, due in 2032 (US$500)	**515**	523
6.10% Notes, denominated in U.S. dollars, due in 2018 (US$1250)	**1 287**	1 308
6.05% Notes, denominated in U.S. dollars, due in 2018 (US$600)	**631**	643
5.00% Notes, denominated in U.S. dollars, due in 2014 (US$400)	**420**	429
4.00% Notes, denominated in U.S. dollars, due in 2013 (US$300)	**308**	313
7.00% Debentures, denominated in U.S. dollars, due in 2028 (US$250)	**267**	271
7.875% Debentures, denominated in U.S. dollars, due in 2026 (US$275)	**318**	325
9.25% Debentures, denominated in U.S. dollars, due in 2021 (US$300)	**390**	402
5.39% Series 4 Medium Term Notes, due in 2037	**600**	600
5.80% Series 4 Medium Term Notes, due in 2018	**700**	700
6.70% Series 2 Medium Term Notes, due in August 2011	**500**	500
	10 199	10 342
Revolving-term debt, with variable interest rates		
Commercial paper, bankers' acceptances and LIBOR loans	**1 570**	3 244
Total unsecured long-term debt	**11 769**	13 586
Secured long-term debt	**13**	13
Capital leases	**322**	326
Debt fair value adjustment for interest swaps	**8**	18
Deferred financing costs	**(60)**	(63)
	12 052	13 880
Current portion of long-term debt		
6.70% Series 2 Medium Term Notes	**(500)**	—
Capital leases	**(10)**	(14)
Debt fair value adjustment for interest swaps	**(8)**	(11)
Total current portion of long-term debt	**(518)**	(25)
Total long-term debt	**11 534**	13 855

At September 30, 2010, unutilized lines of credit were $5,742 million, as follows:

($ millions)	2010
Facility that has a term period of one year and expires in 2011	**4**
Facility that is fully revolving for a period of four years and expires in 2013	**206**
Facilities that are fully revolving for a period of five years and expire in 2013	**7 320**
Facilities that can be terminated at any time at the option of the lenders	**466**
Total available credit facilities	**7 996**
Credit facilities supporting outstanding commercial paper, bankers' acceptances and LIBOR loans	**(1 570)**
Credit facilities supporting letters of credit	**(684)**
Total unutilized credit facilities	**5 742**

14. CAPITAL STRUCTURE FINANCIAL POLICIES

The company's primary capital management objective is to maintain a solid investment-grade credit rating profile. This objective affords the company the financial flexibility and access to the capital it requires to execute on its growth objectives.

The company's capital is monitored through net debt to cash flow from operations[(1)] and total debt to total debt plus shareholders' equity.

Net debt to cash flow from operations is calculated as short-term debt plus total long-term debt less cash and cash equivalents divided by the twelve-month trailing cash flow from operations.

Total debt to total debt plus shareholders' equity is calculated as short term-debt plus total long-term debt divided by short-term debt plus total long-term debt plus shareholders' equity.

Financial covenants associated with the company's various banking and debt arrangements are reviewed regularly and controls are in place to maintain compliance with these covenants. The company complied with all financial covenants for the periods ended September 30, 2010 and December 31, 2009.

During the third quarter of 2010, the company's strategy was to maintain the measure set out in the following schedule. The company believes that maintaining the capital target helps to provide the company access to capital at a reasonable cost by maintaining solid investment-grade credit ratings.

At September 30 ($ millions)	Capital Measure Target	2010	2009
Components of ratios			
Short-term debt		**2**	3
Current portion of long-term debt		**518**	21
Long-term debt		**11 534**	13 826
Total debt		**12 054**	13 850
Less: Cash and cash equivalents		**598**	587
Net debt		**11 456**	13 263
Shareholders' equity		**35 728**	33 854
Total capitalization (total debt plus shareholders' equity)		**47 782**	47 704
Cash flow from operations[(1)] (trailing twelve months)		**5 641**	1 901
Net debt to cash flow from operations	<2.0 times	**2.0**	7.0
Total debt to total debt plus shareholders' equity		**25%**	29%

(1) Cash flow from operations is calculated as cash flow from operating activities before changes in non-cash working capital.

The company's capital management strategy, objectives, definitions, monitoring measures and targets have not changed significantly from the prior period.

15. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

The components of accumulated other comprehensive income (loss), net of income taxes, are as follows:

($ millions)	**September 30 2010**	December 31 2009
Unrealized foreign currency translation adjustment	**(472)**	(248)
Unrealized gains on derivative hedging activities	**14**	15
Total	**(458)**	(233)

16. SUPPLEMENTAL INFORMATION

	Three months ended September 30		Nine months ended September 30	
($ millions)	**2010**	2009	**2010**	2009
Interest paid	**226**	63	**573**	297
Income taxes paid	**296**	521	**567**	676

P.O. Box 2844, 150-6th Avenue S.W., Calgary, Alberta, Canada T2P 3E3
tel: (403) 296-8000 fax: (403) 296-3030 info@suncor.com www.suncor.com