SECOND QUARTER 2010
Report to shareholders for the period ended June 30, 2010

Suncor Energy 2010 second quarter results – strategy on track

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 pages 37 to 42 of our report to shareholders for the period ended June 30, 2010. Certain crude oil and natural gas liquid volumes have been converted to millions of cubic feet equivalent of natural gas (mmcfe) or thousands of cubic feet equivalent of natural gas (mcfe) 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, mcfe, 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 well head.

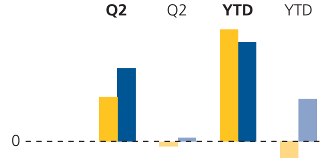
On August 1, 2009, Suncor Energy Inc. completed its merger with Petro-Canada. As such, the results for the three months ended June 30, 2010 reflect the results of the post-merger Suncor and the comparative figures for the three months ended June 30, 2009 reflect solely the results of legacy Suncor prior to the merger.

Suncor Energy Inc. recorded second quarter 2010 net earnings of $480 million ($0.31 per common share), compared to a net loss of $51 million ($0.06 per common share) for the second quarter of 2009. Operating earnings(1) in the second quarter of 2010 were $781 million ($0.50 per common share), compared to $38 million ($0.04 per common share) in the second quarter of 2009.

The increase in operating earnings was primarily due to additional upstream production as a result of the August 2009 merger with Petro-Canada, as well as higher benchmark prices in the second quarter of 2010, compared to the second quarter of 2009. This was partially offset by the stronger Canadian dollar, relative to the U.S. dollar.

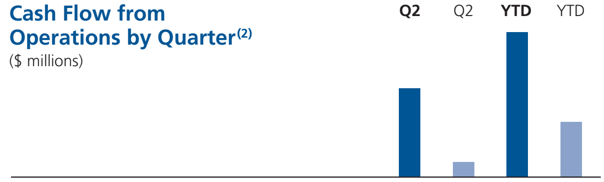
Cash flow from operations(2) was $1.758 billion ($1.13 per common share) in the second quarter of 2010, compared to $295 million ($0.31 per common share) in the second quarter of 2009. The increase in cash flow from operations was primarily due to production volumes added as a result of the merger as well as higher realized prices.

Earnings by Quarter
($ millions)



	2010 Q2	2009 Q2	**2010 YTD**	2009 YTD
Net earnings (loss)	**480**	(51)	**1 196**	(240)
Operating earnings(1)	**781**	38	**1 068**	455

Cash Flow from Operations by Quarter(2)
($ millions)



2010 Q2	2009 Q2	**2010 YTD**	2009 YTD
1 758	295	**2 882**	1 096

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

	2010 Q2	2009 Q2	**2010 YTD**	2009 YTD
Other	**299.5**	35.1	**314.7**	35.8
Oil Sands (including Syncrude)	**334.4**	301.0	**284.9**	289.0
Total	**633.9**	336.1	**599.6**	324.8

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

	2010	2009
Return on average shareholders' equity	**7.9**	2.6
Return on capital employed(4)	**7.0**	7.3

(1) Non-GAAP measure. See pages 38 to 39 for a reconciliation of net earnings to operating earnings.

(2) Non-GAAP measure. See pages 40 to 41.

(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 39.

Operating Earnings

Operating earnings is a non-GAAP measure that the company uses to evaluate operating performance, which management believes allows better comparability between periods. Operating earnings is calculated by adjusting net earnings for significant one-time items and items that are not indicative of operating performance.

Three months ended June 30 ($ millions, after-tax)	**2010**	2009
Net earnings (loss) as reported	**480**	(51)
Change in fair value of commodity derivatives used for risk management(1)	**(149)**	442
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**330**	(405)
Mark-to-market valuation of stock-based compensation	**(7)**	17
Project start-up costs	**12**	7
Costs related to deferral of growth projects	**24**	28
Merger and integration costs	**23**	—
Gains on significant disposals	**(112)**	—
Impairments and write-offs(2)	**156**	—
Adjustments to provisions for assets acquired through the merger(3)	**24**	—
Operating earnings	**781**	38

(1) 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 which are not adjusted for.

(2) For more information on impairments and write-offs refer to note 5 of the unaudited Interim Consolidated Financial Statements.

(3) Adjustments were 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 during the second quarter of 2010.

Suncor's total upstream production during the second quarter of 2010 averaged 633,900 boe per day, compared to 336,100 boe per day in the second quarter of 2009, primarily reflecting additional upstream production resulting from the merger.

Oil Sands production (excluding proportionate production share from the Syncrude joint venture) contributed an average 295,500 barrels per day (bpd) in the second quarter of 2010, compared to second quarter 2009 production of 301,000 bpd. Second quarter 2010 production was impacted by planned maintenance at one of two oil sands upgraders in May and June.

"Prior to heading into planned maintenance this quarter, we achieved record monthly oil sands average production of 333,000 barrels per day in April," said Rick George, president and chief executive officer. "Even with the impacts of maintenance, we had one of our best quarters for oil sands production on record. Although we have some planned maintenance remaining, we're targeting a strong second half to the year."

Cash operating costs for Suncor's oil sands operations (excluding Syncrude) increased to $35.90 per barrel in the second quarter of 2010, compared to $31.30 per barrel during the second quarter of 2009. The increase in cash operating costs per barrel was primarily due to the inclusion of MacKay River costs as a result of the merger, higher product purchase costs and additional maintenance in the second quarter of 2010 compared to the second quarter of 2009.

Suncor's proportionate production share from the Syncrude joint venture contributed an average of 38,900 bpd of production during the second quarter of 2010.

Production from the Natural Gas business averaged 586 mmcfe per day in the second quarter of 2010, compared to 211 mmcfe per day during the second quarter of 2009, primarily due to the addition of Petro-Canada natural gas assets.

Suncor's International and Offshore business contributed an average of 201,900 boe per day of production in the second quarter of 2010. Production rates were impacted by planned maintenance at the company's North Sea operations and by production quotas in Libya. These impacts were partially offset by strong production in East Coast Canada operations and new production from the Ebla gas project in Syria, which was commissioned in April.

Total sales of refined petroleum products from the Refining and Marketing business averaged 89,000 cubic metres per day during the second quarter of 2010 compared to 33,900 cubic metres per day in the second quarter of 2009, reflecting additional sales volumes from the merger with Petro-Canada.

Strategy and Operational Update

Construction continued on the Firebag Stage 3 in situ oil sands project. The planned $3.6 billion expansion is expected to achieve first production during the second quarter of 2011, with volumes ramping up over an estimated 18 to 24 month period toward a planned production capacity of approximately 62,500 bpd of bitumen.

Spending on engineering for Firebag Stage 4 is expected to continue in 2010 with a target of first bitumen production in the fourth quarter of 2012. Construction of the project, which also has a planned production capacity of 62,500 bpd of bitumen, remains subject to Board of Directors approval.

To support current and future mine reclamation, Suncor applied for and received regulatory approval for a new tailings management plan using the company's proprietary TRO$_{TM}$ tailings management process*. Capital spending for large scale implementation of TRO$_{TM}$ remains subject to Board of Directors approval.

In Suncor's renewable energy business, construction continued on expansion of the company's St. Clair Ethanol Plant. Work currently underway is expected to double the plant's production capacity, with completion targeted toward the end of 2010. The renewable energy business also received regulatory approval for construction of a new wind power project, Suncor's fifth, in southern Alberta.*

As part of its strategic business alignment, Suncor continued with plans to divest of a number of non-core assets. In the second quarter, Suncor closed the sale of assets known as Rosevear and Pine Creek for net proceeds of $229 million and signed another agreement to sell non-core natural gas properties in Alberta for gross proceeds of $285 million, before closing adjustments. Suncor also reached an agreement to sell all of its shares in Petro-Canada Netherlands B.V. for gross proceeds of €445 million, before closing adjustments. It is anticipated that this sale will close in the third quarter of 2010. The sales that have not closed are subject to the satisfaction of customary closing conditions.

To date, Suncor has disposed of, or reached agreements to dispose of, assets for aggregate consideration of approximately $2.4 billion prior to closing adjustments. Additional assets planned for divestiture include certain natural gas assets in Western Canada as well as North Sea assets in the Scott/Telford and Triton areas.

"One year out from our historic merger with Petro-Canada, we're very pleased with the progress we've seen," said George. "Sales of non-core assets have proceeded well and our growth plans are on track. Every part of this business, from our core oil sands operations and conventional and offshore oil and gas production to our downstream refining and marketing division is delivering on strategy."

**For more information on the TRO tailings management process, wind power projects and other elements of Suncor's environmental, economic and social performance, see our 2010 Report on Sustainability at www.suncor.com/sustainability, which is not incorporated by reference in this MD&A.*

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 May 4, 2010. The revisions are principally as follows:

- the Syncrude production outlook has been adjusted to 36,000 bpd (+/−5%) from 38,000 bpd (+/−5%) primarily due to operational issues at the Syncrude facilities in the second quarter of 2010;
- the Natural Gas production outlook related to remaining targeted divestitures has been adjusted to 140 mmcfe per day from 180 mmcfe per day as a result of completed dispositions of our Rosevear and Pine Creek properties during the second quarter of 2010 and the change in the assets targeted for potential sale; and
- the East Coast Canada production outlook has been adjusted to 65,000 bpd (+/−5%) from 60,000 bpd (+/−5%) primarily as a result of improved performance to date.

These changes to the operational outlook have a corresponding impact on the total production outlook which has been adjusted to 610,000 boe per day (+/−5%) from 608,000 boe per day (+/−5%) and total production related to remaining targeted divestitures, which has been adjusted to 63,000 boe per day from 70,000 boe per day.

	Six Months Actual Ended June 30, 2010	2010 Full Year Outlook
Total production (boe per day) – before remaining targeted divestitures (1)	**599,600**	610,000 (+/− 5%)
Total production (boe per day) – related to remaining targeted divestitures (1)	**N/A**	63,000
Oil Sands (2)		
Production (bpd)	**249,300**	280,000 (+/− 5%)
Sales		
Diesel	**9%**	9%
Sweet	**31%**	36%
Sour	**44%**	46%
Bitumen	**16%**	9%
Realization on crude sales basket (3)	**WTI @ Cushing less Cdn$9.37 per barrel**	WTI @ Cushing less Cdn$7.00 to Cdn$8.00 per barrel
Cash operating costs (4)	**$43.50 per barrel**	$38 to $42 per barrel
Syncrude production (bpd)	**35,600**	36,000 (+/− 5%)
Natural Gas		
Production (mmcfe per day) – before remaining targeted divestitures (1)	**659**	580 (+/− 5%)
Production (mmcfe per day) – related to remaining targeted divestitures (1)	**N/A**	140
Natural gas	**90%**	91%
Crude oil and liquids	**10%**	9%
East Coast Canada		
Production (bpd)	**72,600**	65,000 (+/− 5%)
International		
Production (boe per day) – before targeted divestitures (1)	**132,300**	133,000 (+/− 5%)
Production (boe per day) – related to remaining targeted divestitures (1)	**N/A**	40,000
Crude oil and liquids (5)	**82%**	84%
Natural gas (5)	**18%**	16%

(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) Pre-divestment.

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 June 30, 2010, for the material risks and assumptions underlying this forward looking information.

MANAGEMENT'S DISCUSSION AND ANALYSIS

July 27, 2010

This Management's Discussion and Analysis (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 – Notice Forward-Looking Information section of this MD&A for information on material risk factors and assumptions underlying our forward-looking information.

This MD&A should be read in conjunction with Suncor's June 30, 2010 unaudited Interim Consolidated Financial Statements and the audited Consolidated Financial Statements and MD&A for the year ended December 31, 2009. 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, including operating earnings, cash flow from operations, return on capital employed (ROCE) and cash and total operating costs referred to in this MD&A, are not prescribed by GAAP and are discussed in the Non-GAAP Financial Measures section of this MD&A.

To provide users with full disclosure relating to potential future capital expenditures, we have provided cost estimates for projects that, in some cases, are still in the early stages of development. These costs are preliminary estimates only. The actual amounts are expected to differ and these differences may be material. Refer to the Significant Capital Project Update section of this MD&A for further discussion of our significant capital projects.

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 unaudited Interim Consolidated Financial Statements.

The unaudited Interim Consolidated Financial statements include the results of post-merger Suncor from August 1, 2009. As such, amounts disclosed in this MD&A for the three and six month periods ended June 30, 2010 and the three month periods ended December 31, 2009, and September 30, 2009 reflect results of the post-merger Suncor whereas the comparative figures for the three and six month periods ended June 30, 2009 and all other comparative periods prior to September 30, 2009 reflect solely the results of legacy Suncor.

References to "we," "our," "us," "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 August 1, 2009 effective date of the merger.

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) or thousands of cubic feet equivalent of natural gas (mcfe) 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, mcfe, 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 well head.

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. Information contained in, or otherwise accessible through our website, does not form a part of this MD&A and is not incorporated into the MD&A by reference.

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.

As part of its ongoing strategic business alignment, Suncor is in the process of divesting a number of non-core Natural Gas assets, all Trinidad and Tobago assets and certain non-core North Sea assets, including all assets in The Netherlands. Assets that have been sold during the period, or that have reached a certain point in the sales process, are presented as discontinued operations, as determined in accordance with GAAP. Certain non-core Natural Gas assets that the company has targeted for potential sale have not met the criteria to be classified as discontinued operations, and are reported as part of the company's continuing operations at this time.

Highlights

- Net earnings for the second quarter of 2010 were $480 million, compared to a net loss of $51 million for the second quarter of 2009. Operating earnings in the second quarter of 2010 were $781 million, compared to $38 million in the second 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 second quarter of 2010 compared to the second quarter of 2009. This was partially offset by the stronger Canadian dollar relative to the U.S. dollar.
- Cash flow from operations was $1.758 billion in the second quarter of 2010, compared to $295 million in the second quarter of 2009. The increase in cash flow from operations was primarily due to production volumes added as a result of the merger, as well as higher realized prices.
- Total upstream production in the current quarter was 633,900 boe per day, compared to 336,100 boe per day in the second quarter of 2009. Additional upstream production, as a result of the merger, and stronger operational performance contributed to the increase.
- Oil Sands (excluding Syncrude) achieved a record monthly average production volume of 333,000 barrels per day (bpd) in the month of April. This was partially offset by planned turnaround activities in May and June that reduced average production in the quarter to 295,500 bpd.
- Commercial production from the Ebla Gas project, in Syria, was achieved on April 19, 2010. Production averaged 12,800 boe per day in the quarter.
- The Trinidad and Tobago asset sale, for gross proceeds of US$380 million, subject to closing adjustments, is now expected to close in the third quarter of 2010. Completion of the sale is subject to customary closing conditions being met.
- On May 31, 2010, the company completed the sale of non-core natural gas properties located in central Alberta, known as Rosevear and Pine Creek, for net proceeds of $229 million.
- On June 23, 2010, the company reached an agreement to sell non-core natural gas properties located in west central Alberta, known as Bearberry and Ricinus, for aggregate gross proceeds of $285 million, subject to closing adjustments. Completion of the sale is subject to customary closing conditions being met.

- The company reached an agreement to sell all of its shares in Petro-Canada Netherlands B.V. for aggregate gross proceeds of €445 million, subject to closing adjustments. Completion of the sale is subject to customary closing conditions being met.
- The company received regulatory approval for a new tailings management plan using the company's proprietary TRO_{TM} tailings management process. Capital spending for large scale implementation of TRO_{TM} remains subject to Board of Directors approval.
- The company received regulatory approval from the Alberta Utilities Commission (AUC) to proceed with the development of its Wintering Hills Wind Power Project. The proposed 88 megawatt (MW) project, located in southern Alberta, is anticipated to consist of up to 55 turbines located on approximately 16,000 acres of privately-owned land.

Some of the highlights above contain forward-looking information, including references to: the ability to meet the conditions of closing, the expected timing of closing and the consideration to be received with respect to the sales of the Trinidad & Tobago assets, the Bearberry and Ricinus assets and the shares in Petro-Canada Netherlands B.V.; and the anticipated number of turbines and MW capacity for such turbines on Suncor's Wintering Hills wind power project. See the Legal Notice – 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)	**June 30 2010**	Mar 31 2010	Dec 31 2009	Sept 30 2009	June 30 2009	Mar 31 2009	Dec 31 2008	Sept 30 2008
Revenues (net of royalties)[(1)]	**9 369**	7 546	7 636	8 443	4 768	4 633	6 952	8 507
Net earnings (loss)								
Continuing operations	**318**	464	473	951	(46)	(189)	(216)	796
Discontinued operations	**162**	252	(16)	(22)	(5)	—	1	19
	480	716	457	929	(51)	(189)	(215)	815
Net earnings (loss) from continuing operations per common share								
Basic	**0.20**	0.30	0.30	0.76	(0.05)	(0.20)	(0.23)	0.85
Diluted	**0.20**	0.30	0.30	0.75	(0.05)	(0.20)	(0.23)	0.84
Net earnings (loss) per common share[(1)]								
Basic	**0.31**	0.46	0.29	0.69	(0.06)	(0.20)	(0.24)	0.87
Diluted	**0.31**	0.45	0.29	0.68	(0.06)	(0.20)	(0.24)	0.86
Operating earnings (loss)								
Continuing operations	**728**	203	339	365	43	380	13	867
Discontinued operations	**53**	84	(16)	(22)	(5)	—	1	19
	781	287	323	343	38	380	14	886
Operating earnings per common share[(1)]	**0.50**	0.18	0.21	0.27	0.04	0.41	0.02	0.95
Cash flow from operations[(1)]	**1 758**	1 124	1 129	574	295	801	231	1 146
Return on capital employed (%)[(2)]	**7.0**	4.9	2.6	3.7	7.3	16.0	22.5	28.7

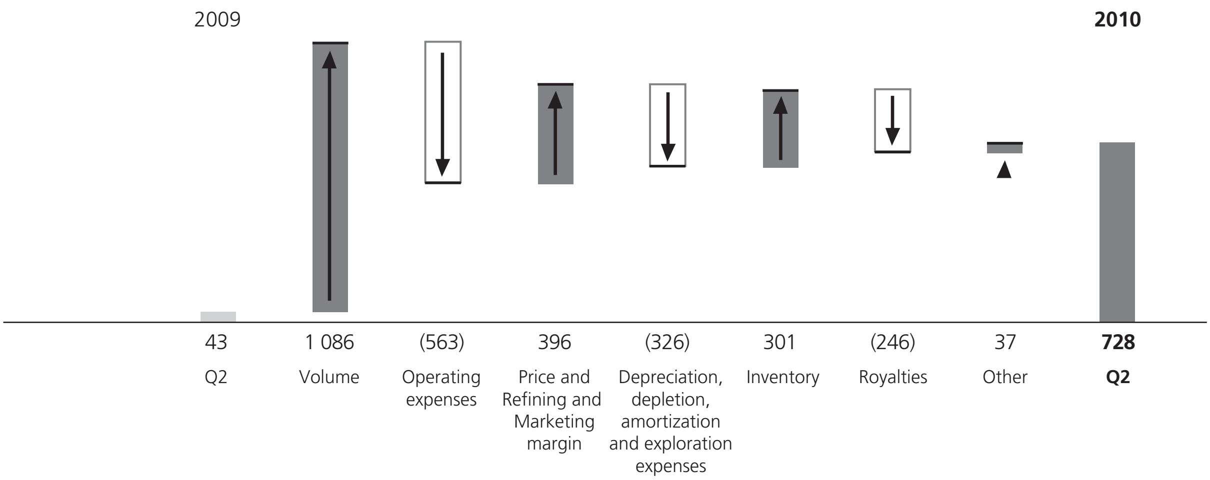
(1) Includes continuing and discontinued operations.

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

Consolidated operating earnings from continuing operations in the second quarter of 2010 were $728 million, compared to $43 million in the second quarter of 2009, primarily due to higher sales volumes, as a result of the merger, and higher benchmark prices, partially offset by the stronger Canadian dollar relative to the U.S. dollar.

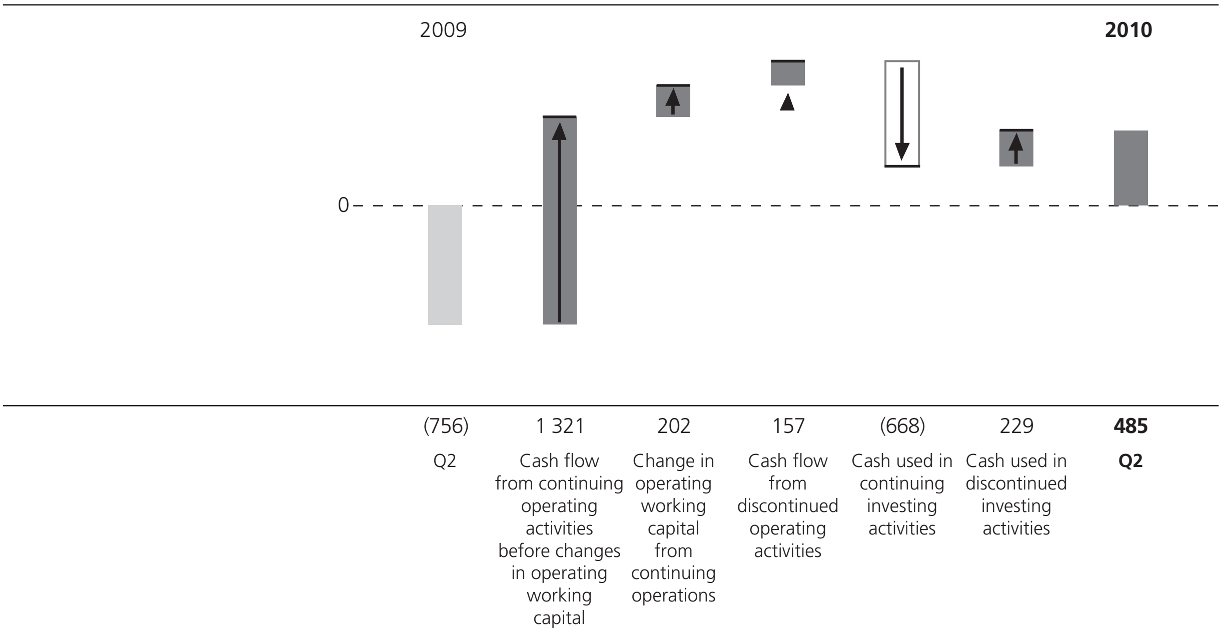
Consolidated Operating Earnings from Continuing Operations

($ millions)



Consolidated Net Cash Flow Before Financing Activities

($ millions)



Volumes

thousands of barrels of oil equivalent per day	Three months ended June 30 2010	2009	Six months ended June 30 2010	2009
Continuing operations				
Oil Sands – operated	**295.5**	301.0	**249.3**	289.0
Oil Sands – Syncrude	**38.9**	—	**35.6**	—
Natural Gas	**71.8**	25.1	**73.8**	24.8
International and Offshore	**168.1**	—	**168.3**	—
	574.3	326.1	**527.0**	313.8
Discontinued operations				
Natural Gas	**25.8**	10.0	**36.0**	11.0
International and Offshore	**33.8**	—	**36.6**	—
	59.6	10.0	**72.6**	11.0
Total	**633.9**	336.1	**599.6**	324.8

Commodity Prices

Average Benchmarks

Three months ended ($ average for the period)		**June 30 2010**	Mar 31 2010	Dec 31 2009	Sept 30 2009	June 30 2009	Mar 31 2009	Dec 31 2008	Sept 30 2008
West Texas Intermediate (WTI) crude oil at Cushing	US$/barrel	**78.05**	78.70	76.20	68.30	59.60	43.10	58.75	118.00
Dated Brent crude oil at Sullom Voe	US$/barrel	**78.30**	76.25	74.55	68.25	58.85	44.40	54.90	114.80
Dated Brent/Maya FOB price differential	US$/barrel	**10.45**	6.50	5.25	5.10	3.75	5.90	10.10	8.35
Canadian 0.3% par crude oil at Edmonton	Cdn$/barrel	**76.30**	80.45	77.00	70.60	65.30	50.10	64.65	123.00
Light/heavy crude oil differential of WTI at Cushing less Western Canadian Select at Hardisty	US$/barrel	**14.05**	8.95	12.10	10.10	7.50	8.95	19.30	18.05
Natural gas (Alberta spot) at AECO	Cdn$/mcf	**3.85**	5.35	4.25	3.00	3.65	5.65	6.80	9.25
New York Harbour 3-2-1 crack (1)	US$/barrel	**12.40**	7.95	5.80	7.50	8.35	9.85	5.40	10.65
Chicago 3-2-1 crack (1)	US$/barrel	**11.05**	5.65	4.15	7.65	10.15	8.95	5.25	16.45
Seattle 3-2-1 crack (1)	US$/barrel	**15.50**	8.55	5.95	12.80	13.35	13.45	5.25	17.20
Gulf Coast 3-2-1 crack (1)	US$/barrel	**9.65**	6.75	4.50	6.75	8.40	8.90	2.90	14.60
Exchange rate	US$/Cdn$	**0.97**	0.96	0.94	0.91	0.85	0.80	0.82	0.96

(1) 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.

SEGMENTED EARNINGS AND CASH FLOWS

Oil Sands

($ millions, unless otherwise noted)	Three months ended June 30 2010	2009	Six months ended June 30 2010	2009
Gross revenues	**2 754**	1 195	**4 724**	2 303
Less: Royalties	**(182)**	(138)	**(252)**	(146)
Net revenues	**2 572**	1 057	**4 472**	2 157
Production (excluding Syncrude) (thousands of bpd)	**295.5**	301.0	**249.3**	289.0
Syncrude production (thousands of bpd)	**38.9**	—	**35.6**	—
Average sales price (excluding Syncrude) ($/barrel) (1)	**69.79**	59.34	**69.95**	59.39
Net earnings (loss)	**517**	(307)	**593**	(417)
Operating earnings	**544**	176	**648**	504
Cash flow from operations	**933**	174	**1 195**	654
Cash operating costs (excluding Syncrude) ($/barrel)	**35.90**	31.30	**43.50**	32.50
Sales mix (sweet/sour mix) (%)	**42/58**	44/56	**40/60**	48/52
ROCE (2)	**9.1**	11.1		
ROCE (3)	**5.7**	6.5		

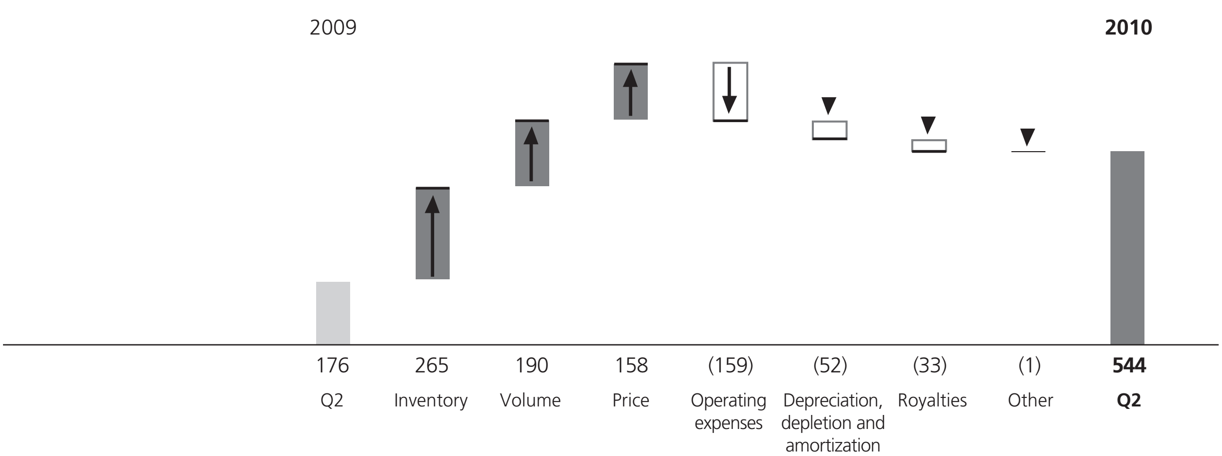
(1) Calculated before royalties and net of related transportation costs.

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

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

Operating Earnings from Continuing Operations

($ millions)



Oil Sands recorded net earnings of $517 million in the second quarter of 2010, compared with a net loss of $307 million in the second quarter of 2009, primarily due to risk management gains in the current year and losses in 2009 as well as improved operating activities in the current year, partially offset by a $141 million write-off of certain mining and extraction equipment. These assets 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.

Operating earnings for the second quarter of 2010 were $544 million, compared to operating earnings of $176 million in the second quarter of 2009. Operating earnings were higher primarily due to increased inventory sales, stronger realized average prices for oil sands crude products and higher total production volumes during the current quarter. Record production, excluding Syncrude, achieved in the month of April was partially offset by planned turnaround activities in May and June that reduced production in the quarter compared to the same quarter in the prior year. Cash flow from operations was $933 million in the second quarter of 2010, compared to $174 million in the second quarter of 2009. The increase was primarily a result of the same factors that impacted operating earnings.

Net earnings for the first six months of 2010 were $593 million, compared with a net loss of $417 million in the first six months of 2009. The increase was a result of the same factors that impacted the second quarter net earnings.

Operating earnings for the first six months of 2010 were $648 million, compared to $504 million in the same period of 2009. Cash flow from operations for the first six months of 2010 increased to $1.195 billion from $654 million in the first six months of 2009. The year-to-date increase in operating earnings and cash flow from operations was primarily due to higher production and overall improved pricing compared to the first six months of 2009. This was partially offset by the impact of the upgrader fires that occurred in the fourth quarter of 2009 and the first quarter of 2010, which resulted in reduced production of approximately 59,000 bpd over the first six months of the year. The fires also had a negative impact on the sales mix with a higher percentage of lower value sour crude being sold compared to prior periods.

Volumes

Oil Sands production averaged 295,500 bpd (excluding Suncor's 12% share in Syncrude) in the second quarter of 2010, compared to 301,000 bpd during the second quarter of 2009. The decrease in production was due to the planned turnaround activities in May and June offset by improved operational reliability resulting in record monthly average production of 333,000 bpd in the month of April.

Suncor's share of Syncrude contributed an average of 38,900 bpd of sweet synthetic crude oil production in the second quarter of 2010, which was 12% of Oil Sands total production. 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 the second quarter of 2009 as volumes processed by Suncor under a processing fee agreement. However, the addition of MacKay River has resulted in increased sales volumes for Oil Sands, as volumes under the processing agreement were not included in sales prior to August 1, 2009.

For the first six months of 2010 Oil Sands production averaged 249,300 bpd (excluding Syncrude), compared to 289,000 bpd for the first six months of 2009. Production was reduced by 59,000 bpd in the first six months of 2010 due to the impact of the upgrader fires that occurred in the fourth quarter of 2009 and the first quarter of 2010. The remaining difference is primarily due to the same factors that impacted production in the second quarter.

Suncor's share of Syncrude contributed an average of 35,600 bpd of sweet synthetic crude oil production in the first six months of 2010, which was 13% of Oil Sands total production.

Prices

Sales price realization from Oil Sands operated assets averaged $69.79 per barrel during the second quarter of 2010, compared to $59.34 per barrel during the same period in 2009. 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. WTI crude oil price averaged US$78.05 per barrel during the second quarter of 2010, compared to US$59.60 per barrel during the same period in 2009, and the US$/Cdn$ exchange rate averaged 0.97 in the second quarter of 2010, compared to 0.85 for the same period in 2009.

During the first six months of 2010, sales price realization from Oil Sands operated assets averaged $69.95 per barrel, compared to $59.39 per barrel during the same period in 2009. Consistent with the second quarter, Oil Sands benefited from higher benchmark crude oil prices in the first half of the year, partially offset by the negative impact of the stronger Canadian dollar. WTI crude oil price averaged US$78.37 per barrel during the first six months of 2010, compared to US$51.35 per barrel during the same period in 2009, and the US$/Cdn$ exchange rate averaged 0.96 in the first six months of 2010, compared to 0.81 for the same period in 2009. The sales mix for the first six months of the year in 2010 was negatively affected by the upgrader fires with the proportion of higher value diesel and sweet crude products decreasing to 40% of total sales volumes from 48% in the first six months of 2009.

Operating Expenses

Operating expenses were higher in the second quarter of 2010, compared to the second quarter of 2009, primarily due to the addition of operating costs from MacKay River and Syncrude, increased purchases of product to facilitate bitumen sales and the timing of maintenance work.

During the second quarter of 2010, cash operating costs (excluding Syncrude) increased to $35.90 per barrel, from $31.30 per barrel in the second quarter of 2009, primarily due to the inclusion of MacKay River costs as a result of the merger, higher product purchase costs and additional maintenance in the second quarter of 2010 compared to the second quarter of 2009.

In the first six months of 2010, operating expenses were higher compared to the first six months of 2009. The increase was primarily due to the same factors that impacted the second quarter operating expenses.

Cash operating costs (excluding Syncrude) for the first six months of 2010, increased to $43.50 per barrel compared to $32.50 per barrel in the first six months of 2009. In addition to the second quarter impacts, the six month period increase in cash operating costs was also impacted by the upgrader fires that occurred in the fourth quarter of 2009 and the first quarter of 2010.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization (DD&A) expenses increased in the second quarter of 2010, compared to the second quarter of 2009. The depreciable cost base has grown since the second quarter of 2009, as new assets have been commissioned and acquired.

During the first six months of 2010, DD&A expenses increased compared to the first six months of 2009 primarily due to the same factors affecting second quarter DD&A expenses.

Royalties

Royalties increased to $182 million in the second quarter of 2010 from $138 million in the second quarter of 2009 primarily due to the addition of MacKay River and Suncor's share of Syncrude, as a result of the merger, and higher royalty rates for pre-payout projects. In situ projects continued in the pre-payout phase and royalties were calculated at the minimum royalty percentage of "Revenues", which is a rate based on the Canadian dollar equivalent of WTI up to a maximum of 9%. For a more detailed description of the Alberta Crown royalty regime in effect for the company's operated Oil Sands assets, see pages 16-18 of Suncor's 2009 Annual Report.

During the first half of 2010, royalty expense increased to $252 million from $146 million in the first half of 2009 primarily due to the same factors affecting royalties in the second quarter described above.

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$/mcf at AECO	4.95	5.25	5.95
Light/heavy crude oil differential of WTI at Cushing less Maya at the U.S. Gulf Coast US$	8.35	10.15	11.50
Differential of Maya at the U.S. Gulf Coast less Western Canadian Select at Hardisty US$	4.60	4.90	5.00
US$/Cdn$ exchange rate	0.85	1.00	1.00
Crown Royalty Expense (based on percentage of total Oil Sands gross revenue (excluding Syncrude))% [1]			
2010 [2]	4-6	8-10	8-10
2011-2013	4-6	9-11	12-14

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

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

The previous table contains forward-looking information and users of this information are cautioned that actual Crown royalty expense may vary materially from the percentages disclosed in the table. The percentages disclosed in the table were developed using the following assumptions: current agreements with the Government of Alberta remaining in force, unamended, royalty rates and other changes enacted effective January 1, 2009 by the Government of Alberta remaining in force, unamended, current forecasts of production, capital and operating costs, and the forward estimates of commodity prices and exchange rates described in the table.

The following risk factors could cause actual royalty rates to differ materially from the rates contained in the foregoing 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. For the year 2009, 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 $260 million at June 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 an impact on royalties payable to the Crown.

For further information on risk factors related to royalty rates, please refer to the 2009 AIF, which risk factors are incorporated herein by reference.

Planned Maintenance Turnarounds

There is a five week planned turnaround scheduled for Upgrader 2 in the third quarter of 2010. Production volumes are expected to be reduced by approximately 35,000 bpd over the duration of the turnaround.

Syncrude is expecting a seven week coker turnaround in the third quarter of 2010.

Growth Update

The company is continuing with its planned growth initiatives related to the Firebag Stage 3 in situ oil sands expansion. The planned $3.6 billion expansion is currently expected to 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 per day.

Spending will also be directed to Firebag Stage 4 with a target of first bitumen production in the fourth quarter of 2012. Firebag Stage 4 also has planned production capacity of 62,500 barrels of bitumen per day. Construction of Firebag Stage 4 remains subject to Board approval.

Remaining 2010 capital growth spending will be directed towards completion of a naphtha unit at Upgrader 2, which is intended to increase the value of the upgrader's product mix. The company expects the naphtha unit will be completed by the end of the fourth quarter of 2011.

The company received regulatory approval for a new tailings management plan using the company's proprietary TRO_{TM} tailings management process. Capital spending for large scale implementation of TRO_{TM} remains subject to Board of Director approval.

Refer to the Significant Capital Projects Update section of this MD&A for an update on our significant capital projects currently in progress.

The growth update provided above and the information on planned maintenance turnarounds, including the expected timing and production reduction, are forward-looking and users are cautioned that actual results may differ materially from those expressed or implied by this forward-looking information and should not place undue reliance on this forward-looking information. Users are referred to the Risk Factors Affecting Performance directly below and to the Legal Notice – Forward-Looking Information section of this MD&A for the material risks and assumptions underlying this forward-looking information.

Risk Factors Affecting Performance

The financial and operating performance of the company's Oil Sands business is potentially affected by a number of factors, including, but not limited to, the following:

- 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. 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 such strategies 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 crude oil and natural gas prices, foreign exchange rates and the light/heavy and sweet/sour crude oil differentials. 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.
- 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. The Communications, Energy and Paperworkers Union Local 707 represent approximately 2,900 Oil Sands employees. The collective agreement with the union expired on April 30, 2010 and the parties continue to operate under the expired agreement. Negotiations are ongoing.

Additional risks, assumptions and uncertainties are discussed in the Legal Notice – Forward-Looking Information section of this MD&A.

Natural Gas

($ millions, unless otherwise noted)	Three months ended June 30 **2010**	2009	Six months ended June 30 **2010**	2009
Gross revenues from continuing operations	**198**	48	**454**	126
Less: Royalties from continuing operations	**(3)**	13	**(39)**	—
Net revenues from continuing operations	**195**	61	**415**	126
Average sales price from continuing operations – natural gas ($/mcf) (1)	**3.40**	3.26	**4.38**	4.32
Average sales price from continuing operations – natural gas liquids and crude oil ($/barrel) (1)	**81.68**	40.04	**77.13**	42.50
Gross production				
Continuing operations (mmcfe/per day)	**431**	151	**443**	149
Discontinued operations (mmcfe/per day)	**155**	60	**216**	66
	586	211	**659**	215
Net earnings (loss)				
Continuing operations	**(68)**	(23)	**(45)**	(33)
Discontinued operations	**113**	(5)	**311**	(5)
	45	(28)	**266**	(38)
Operating earnings (loss)				
Continuing operations	**(37)**	(23)	**(48)**	(33)
Discontinued operations	**4**	(5)	**34**	(5)
	(33)	(28)	**(14)**	(38)
Cash flow from continuing operations	**82**	33	**214**	68
ROCE %	**3.4**	(1.7)		

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

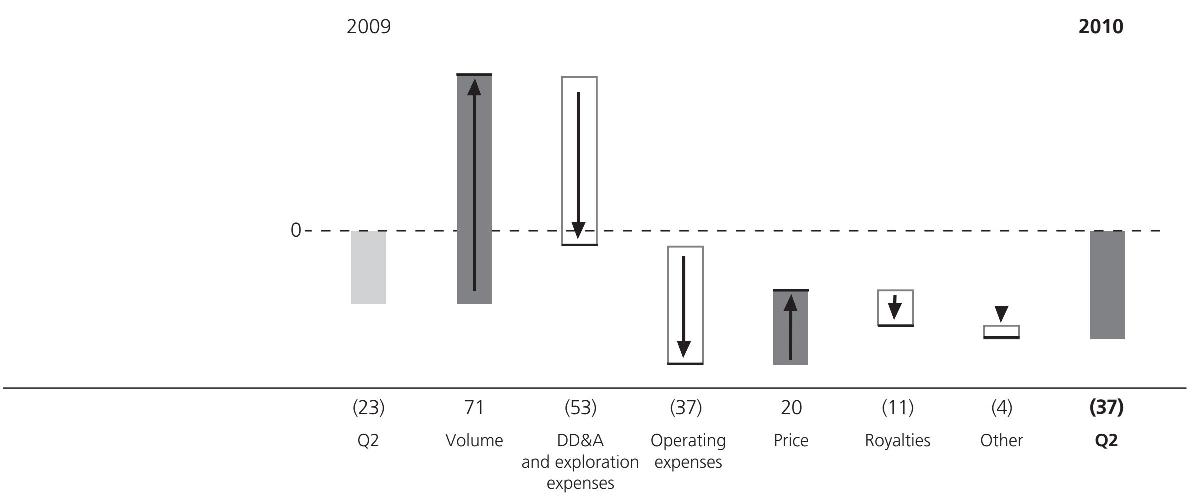
The Natural Gas business recorded net earnings of $45 million in the second quarter of 2010, compared with a net loss of $28 million in the second quarter of 2009. Net earnings in the second quarter of 2010 includes a $110 million gain on asset dispositions partially offset by a $33 million write-down of certain land leases in Western Canada and Alaska that the company is no longer pursuing as part of its strategic business alignment. Total operating loss for the second quarter of 2010 was $33 million, compared to an operating loss of $28 million in the second quarter of 2009. The increase in operating loss was primarily due to higher DD&A and cash expenses related to incremental production volumes as a result of the merger. This was partially offset by higher exploration expenses in 2009.

Net earnings for the first six months of 2010 were $266 million, compared to a net loss of $38 million in the first six months of 2009. The year-to-date increase in net earnings was primarily due to the gains recorded on asset sales during the first six months of 2010 partially offset by the write-down of certain land leases in the second quarter of 2010. Total operating loss for the first six months of 2010 was $14 million, compared to an operating loss of $38 million in the same period of 2009. The year-to-date decrease in operating loss was primarily due to the same factors that impacted second quarter operating earnings, offset by higher operating earnings from discontinued operations in the first quarter of 2010.

Continuing Operations

Operating Loss from Continuing Operations

($ millions)



Operating loss from continuing operations was $37 million in the second quarter of 2010, compared to an operating loss from continuing operations of $23 million in the second quarter of 2009. The increased operating loss from continuing operations was due to the same factors that impacted total operating losses. Cash flow from continuing operations for the second quarter of 2010 was $82 million, compared to $33 million in the second quarter of 2009. The increased cash flow from continuing operations was due primarily to the cash generated from the assets acquired during the merger.

Operating loss from continuing operations for the first six months of 2010 was $48 million, compared to an operating loss from continuing operations of $33 million in the first six months of 2009. Cash flow from continuing operations for the first six months of 2010 increased to $214 million from $68 million in the first six months of 2009. The year-to-date decrease in operating losses and increase in cash flow from continuing operations were primarily due to the same factors that impacted second quarter operating losses and cash flow from continuing operations.

Volumes

Continuing operations production averaged 431 mmcfe per day in the second quarter of 2010, compared to 151 mmcfe per day during the same period in 2009. The increase primarily reflects assets acquired as a result of the merger, partially offset by natural declines.

Production from continuing operations averaged 443 mmcfe per day for the first six months of 2010, compared to 149 mmcfe per day during the first six months of 2009. The increase is primarily due to the same factors that affected volumes in the second quarter.

Prices

The average realized natural gas price increased to $3.40 per mcf in the second quarter of 2010, compared to $3.26 per mcf in the second quarter of 2009. The average realized natural gas liquids and crude oil price increased to $81.68 per barrel in the second quarter of 2010, from $40.04 per barrel in the second quarter of 2009. Benchmark natural gas price and crude oil prices were higher in the second quarter of 2010, compared to the second quarter in 2009.

The average realized natural gas price for the first six months of 2010 increased to $4.38 per mcf compared to $4.32 per mcf for the first six months of 2009. Benchmark natural gas prices during the first half of 2010 are consistent with the first half of 2009. The average realized natural gas liquids and crude oil price increased to $77.13 per barrel in the first six months of 2010, from $42.50 per barrel in the first six months of 2009. Benchmark crude oil prices were higher during the first half of 2010, compared to the same period in 2009.

Operating Expenses

Operating expenses including general expenses, from continuing operations increased in the second quarter of 2010 primarily as a result of increased production levels, partially offset by operational efficiencies. Total operating expenses on a per mcfe basis were lower in the second quarter of 2010 ($2.14 per mcfe), compared to the second quarter of 2009 ($2.33 per mcfe) primarily as a result of operational efficiencies and the timing of certain maintenance work.

Operating expenses from continuing operations increased in the first six months of 2010 compared to the first six months of 2009. Total operating expenses on a per mcfe basis were lower in the first six months of 2010 ($1.95 per mcfe), compared to the first six months of 2009 ($2.48 per mcfe). The decrease in total operating expenses on a mcfe basis was due to the same factors impacting the second quarter.

DD&A and Exploration Expenses

DD&A expenses from continuing operations increased in the second quarter of 2010 compared to the same period in 2009 due to the increase in capital assets as a result of the merger. On a per unit basis, DD&A expenses have increased quarter over quarter. Lower reserves in certain areas at the end of 2009 due to lower pricing has increased Suncor's DD&A rates in 2010. This was partially offset by higher exploration expenses in the second quarter of 2009.

DD&A expenses from continuing operations increased in the first six months of 2010 compared to the same period in 2009 primarily due to the same factors that impacted DD&A in the second quarter.

Royalties

In the second quarter of 2010, total Crown royalties from continuing operations increased to $3 million, from a recovery of $13 million in the second quarter of 2009. The increased royalties were primarily associated with the production acquired as part of the merger. On May 27, 2010, the Alberta Government issued revised royalty policies for Conventional Oil and Gas production. These revised policies had no material impacts on our second quarter results.

Total royalties from continuing operations increased to $39 million in the first six months of 2010, from nil in the first six months of 2009. The increase is primarily due to the same factors that impacted the second quarter results.

Discontinued Operations

Discontinued operations 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 second quarter of 2010.

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

- On May 31, 2010, the company sold non-core natural gas properties located in central Alberta, known as Rosevear and Pine Creek, for net proceeds of $229 million with an effective date of January 1, 2010. These assets produced an average of 21 mmcfe per day during April and May of 2010.

- On June 23, 2010, the company reached an agreement, subject to customary closing conditions, to sell non-core natural gas properties located in west central Alberta, known as Bearberry and Ricinus. These assets produced an average of 36 mmcfe per day during the second quarter of 2010. The sale, for gross proceeds of $285 million before closing adjustments, is expected to close during the third quarter of 2010, with an effective date of April 1, 2010.

The above contains forward-looking information, including references to the ability of the closing conditions to be met, the expected timing of closing and the consideration to be received with respect to the sale of the Bearberry and Ricinus assets. See the Legal Notice – Forward-Looking Information section of this MD&A for the material risks and assumptions underlying this forward-looking information.

Risk Factors Affecting Performance

The financial and operating performance of the company's Natural Gas business is potentially affected by a number of factors, including, but not limited to, the following:

- Consistently and competitively finding and developing reserves that can be brought on stream economically.
- 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.
- Volatility in natural gas and liquids prices is not predictable and can significantly impact revenues.
- The accessibility and cost of mineral rights. Market demand influences the cost and available opportunities for mineral leases and acquisitions.
- Risk associated with a depressed market for asset sales, leading to losses on disposition.
- 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.
- 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.
- 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. These risks and uncertainties include 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.

Additional risks, assumptions and uncertainties are discussed in the Legal – Notice Forward-Looking Information section of this MD&A.

International and Offshore

($ millions, unless otherwise noted)	2010 Three months ended June 30	Six months ended June 30
Gross revenues from continuing operations	**1 310**	**2 514**
Less: Royalties	**(314)**	**(650)**
Net revenues from continuing operations	**996**	**1 864**
Production from continuing operations (thousands of boe/d)		
East Coast Canada	**70.6**	**72.6**
U.K. (Buzzard)	**49.3**	**53.9**
Libya	**35.4**	**35.4**
Syria (1)	**12.8**	**6.4**
Production from discontinued operations (thousands of boe/d)	**33.8**	**36.6**
Total production (thousands of boe/d)	**201.9**	**204.9**
Average sales price from continuing operations (2)		
East Coast Canada ($/bbl)	**76.88**	**77.80**
U.K. (Buzzard) ($/boe)	**80.35**	**77.03**
Other International ($/boe)	**76.14**	**76.96**
Net earnings		
Continuing operations	**217**	**426**
Discontinued operations	**49**	**103**
	266	**529**
Operating earnings		
Continuing operations	**246**	**451**
Discontinued operations	**49**	**103**
	295	**554**
Cash flow from continuing operations	**517**	**1 059**
ROCE (%) (3)	**16.2**	
ROCE (%) (4)	**10.5**	

(1) Production from Syria averaged 15.9 thousands of boe/d from the date commercial production commenced on April 19, 2010.

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

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

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

Suncor has continuing operations in the U.K. (Buzzard – 29.9% working interest), Norway (exploration), Libya, Syria and East Coast Canada. There are discontinued operations located in The Netherlands and certain U.K. sections of the North Sea, as well as Trinidad and Tobago.

Net earnings for International and Offshore were $266 million in the second quarter of 2010, while operating earnings for the same period in 2010 were $295 million. Net earnings for the quarter included $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. Operating earnings in the second quarter were impacted by higher than expected commodity prices and overall strong production results. This was partially offset by ongoing production quota restraints in Libya and a three week maintenance turnaround at Buzzard.

In the first six months of 2010, net earnings for International and Offshore were $529 million while operating earnings for the same period in 2010 were $554 million. The year-to-date results are consistent with the current quarter.

Continuing Operations

Operating earnings from continuing operations were $246 million in the second quarter of 2010. Cash flow from continuing operations in the same period were $517 million. Both operating earnings and cash flow from continuing operations were primarily impacted by strong prices and production.

Operating earnings from continuing operations were $451 million for the first six months of 2010. Cash flow from continuing operations was $1.059 billion for same period. The year-to-date results were impacted by the same factors as the current quarter.

Volumes

Net production from the Buzzard development in the U.K. sector of the North Sea averaged 49,300 boe per day, reflecting the planned turnaround in the second quarter of 2010. Suncor's share of production in Libya, which averaged 35,400 bpd in the second quarter of 2010, continues to be negatively affected by production quotas. Commercial production from the newly commissioned Ebla natural gas plant in Syria was achieved on April 19, 2010 with production averaging 12,800 boe per day in the second quarter of 2010.

East Coast Canada averaged production of 70,600 bpd in the second quarter of 2010. Suncor's share of production from Terra Nova averaged 27,200 bpd for the quarter. This was ahead of plan due to better than expected reliability and delaying a planned turnaround until the third quarter of 2010. The company's share of production from Hibernia averaged 30,100 bpd for the quarter ended June 30, 2010, due to drilling performance and higher than planned reservoir capability and facility reliability continuing throughout the period. Suncor's share of White Rose's average production for the second quarter of 2010 was 13,300 bpd, which was impacted by lower well productivity and the timing of the North Amethyst extension field coming on line.

For the first six months of 2010 net production from the Buzzard development averaged 53,900 boe per day, which was impacted by unplanned maintenance and a planned turnaround in the first six months of 2010. Suncor's share of production in Libya, which averaged 35,400 bpd in the first six months of 2010, was negatively affected by the production quotas that also impacted the second quarter.

During the first six months of 2010, East Coast Canada production averaged 72,600 bpd. Suncor's share of production from Terra Nova averaged 28,400 bpd for the first six months of 2010. The company's share of production from Hibernia averaged 30,200 bpd during the first six months of 2010. Suncor's share of White Rose's average production for the first six months of 2010 was 14,000 bpd. Production was primarily impacted by the same factors affecting the second quarter production.

Prices

The average sales price for the U.K. (Buzzard) production was $80.35 per boe in the second quarter of 2010, while the average sales price for Libya and Syria production was $76.14 per boe. In the second quarter of 2010, East Coast Canada offshore average sales price was $76.88 per barrel.

For the first six months of 2010, the average sales price for the U.K. (Buzzard) production was $77.03 per boe, while the average sales price for Libya and Syria production was $76.96 per boe. In the first six months of 2010, East Coast Canada offshore average sales price was $77.80 per barrel.

Operating Expenses

Operating expenses from continuing operations were lower than management expectations due to lower operating costs at each of the non-operated East Coast Canada assets, partially due to delayed turnarounds, and favorable foreign exchange rates during the quarter and for the first six months of 2010.

Depreciation, Depletion and Amortization

DD&A expenses from continuing operations were higher than expected during the second quarter of 2010 and the year to date period reflecting higher than anticipated production levels in the East Coast Canada, combined with rate changes.

Royalties

Total royalties in the International and Offshore segment during the second quarter of 2010 were $314 million, or 24% of gross revenue from continuing operations. Royalties were above management expectations primarily as a result of higher volumes and lower capital expenditures than planned for East Coast Canada.

In the six months of 2010, royalties in the International and Offshore segment were $650 million, or 26% of gross revenue from continuing operations.

The following table provides an estimation of royalties related to Suncor's East Coast Canada assets for 2010 to 2013 for three price scenarios, and certain assumptions on which we have based our estimates for those price scenarios.

WTI Price/bbl US$	**60**	**80**	**100**
US$ / Cdn$ exchange rate	0.85	1.00	1.00
Crown Royalty Expense (based on percentage of gross revenue) %			
2010 – Crude (1)	32-34	32-34	33-35
2011 – 2013	21-26	22-27	24-31

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

For a further discussion on Crown royalties, see page 18 of Suncor's 2009 Annual Report. The previous table contains forward-looking information and users of this information are cautioned that actual Crown royalty expense may vary materially from the percentages disclosed in the table. The percentages disclosed in the table 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 table.

The following risk factors could cause actual royalty rates to differ materially from the rates contained in the foregoing 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 impact 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 an impact on royalties payable to the Crown.

Planned Maintenance Turnarounds

In East Coast Canada, there is a four week turnaround scheduled for Terra Nova during the third quarter, and a three week turnaround scheduled for White Rose in the fourth quarter of 2010.

Discontinued Operations

Discontinued operations 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 second quarter of 2010.

During the second quarter of 2010, the International and Offshore business continued its progress on strategic divestment activities:

- The company reached an agreement to sell all of its shares in Petro-Canada Netherlands B.V., subject to customary closing conditions, with an effective date of January 1, 2010. The sale, for gross proceeds of €445 million, subject to closing adjustments, is expected to close in the third quarter of 2010. Petro-Canada Netherlands B.V. has operated interests in eight offshore production and exploration licenses, with average production of 9,500 boe per day in the second quarter of 2010, and has interests in thirteen non-operated offshore production and exploration licenses.
- Suncor entered into an agreement to sell all of its assets in Trinidad and Tobago subject to customary closing conditions, for gross proceeds of US$380 million, subject to closing adjustments. The sale is now expected to close in the third quarter of 2010. Average production of offshore natural gas at the Trinidad and Tobago operations was 11,100 boe per day during the second quarter of 2010.
- North Sea assets that are planned to be divested include the Scott/Telford and Triton area fields. Average production from these assets in the second quarter of 2010 was 13,200 boe per day.

The above contains forward-looking information, including references to: the ability of the closing conditions to be met, the expected timing of closing and the consideration to be received with respect to the sales of the Trinidad & Tobago assets and the shares in Petro-Canada Netherlands B.V.; and the plan to divest certain North Sea assets. See the Legal Notice – Forward-Looking Information section of this MD&A for the material risks and assumptions underlying this forward-looking information.

Growth Update

In Syria, first commercial gas and condensate production was achieved in April and first liquefied petroleum gas was achieved in May from the Ebla gas project. The project, which involved the development of gas fields and building a gas treatment plant, was completed in the second quarter of 2010. Current production rates are approximately 12,800 boe per day.

Two seismic survey projects continue to acquire data in relation to the new Libya Exploration and Production Sharing Agreements. The seismic data acquired during 2009 is currently being processed and interpreted. The focus of the exploration team is to identify drillable prospects and select drilling locations for end of 2010 and 2011. The first exploration appraisal well was completed May 31, 2010. The second exploration well is scheduled to be completed in July 2010.

First oil was achieved May 31, 2010 on the North Amethyst portion of the White Rose Extensions. Facilility construction is complete and the remainder of the project is focused on development drilling of 11 wells, in total, which is anticipated to continue through 2012.

Development drilling for the first phase of the West White Rose development is expected to begin in the third quarter of 2010, with first oil expected by early 2011.

First oil was achieved during the latter part of 2009 on the AA Block area of Hibernia South, in which Suncor holds a 20% interest. Primary production from the remainder of the Hibernia South Extension project, in which Suncor holds a 19.5% interest, is expected in 2011. In February 2010, final agreements were executed among the co-ventures and the Government of Newfoundland and Labrador, including the settlement of transportation deductions for royalty purposes.

Preliminary engineering activities continue on the Hebron project with front end engineering and design expected to begin in the third quarter of 2010.

Refer to the Significant Capital Projects Update section of this MD&A for an update on our significant capital projects currently in progress.

The growth update provided above and the planned maintenance turnarounds referred to above contain forward-looking information, including references to: expected turnaround periods; the expected completion date for the future exploration wells; future drilling, engineering and design plans, as the case may be, for North Amethyst and Hebron; and the schedule for drilling development and expected production timelines for the West White Rose and Hibernia South Extension development. See the Legal Notice – Forward-Looking Information section of this MD&A for the material risks and assumptions underlying this forward-looking information.

Risk Factors Affecting Performance

The financial and operating performance of the company's International and Offshore business is potentially affected by a number of factors, including, but not limited to, the following:

- 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.
- Consistently and competitively finding and developing reserves that can be brought on stream economically.
- Volatility in crude oil and gas prices is not predictable and can significantly impact revenues.
- 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.
- 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.
- Risks associated with applicable legal and other regulatory requirements, including changes to tax, environmental and other legal and regulatory requirements, the outcome of which is not predictable and could result in changes to the company's planned investments, and rates of return on the company's existing investments.
- 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.
- 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. These risks and uncertainties include 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.

Additional risks, assumptions and uncertainties are discussed in the Legal – Notice Forward-Looking Information section of this MD&A.

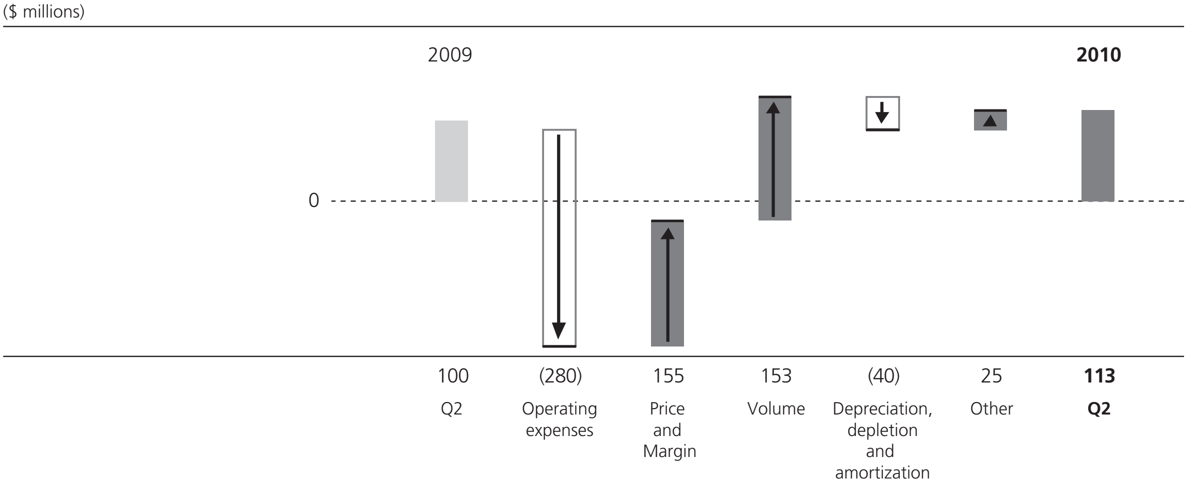
Refining and Marketing

($ millions, unless otherwise noted)	Three months ended June 30 2010	2009	Six months ended June 30 2010	2009
Revenues	**5 233**	1 842	**10 042**	3 256
Refined product sales volumes (thousands of cubic metres per day)				
Gasoline	**40.6**	17.6	**39.4**	17.0
Distillate	**32.0**	10.4	**30.1**	10.5
Other	**16.4**	5.9	**16.3**	5.2
	89.0	33.9	**85.8**	32.7
Net earnings	**138**	99	**277**	211
Operating earnings	**113**	100	**244**	211
Cash flow from operations	**263**	189	**591**	399
ROCE (%)	**5.8**	0.7		

The Refining and Marketing business recorded net earnings of $138 million in the second quarter of 2010, compared with $99 million in the second quarter of 2009. Operating earnings for the second quarter of 2010 were $113 million, compared with $100 million for the second quarter of 2009. Net earnings exceeded operating earnings in the quarter because of a $22 million reduction to the Montreal coker shut-down and decommissioning provision. As a result of the merger, refining capacity has increased by 265,000 bpd or 149%. This increase, combined with the addition of the Petro-Canada national retail and wholesale businesses and the lubricants plant, enabled Refining and Marketing to deliver higher operating earnings in the second quarter of 2010, compared to the second quarter of 2009. Cash flow from operations was $263 million in the second quarter of 2010, compared to $189 million in the same period of 2009. The increase was a result of the same factors that affected second quarter operating earnings.

Net earnings for the first six months of 2010 were $277 million, compared to $211 million in the first six months of 2009. The increase in net earnings was primarily due to the same factors that affected the second quarter. Operating earnings for the first six months of 2010 were $244 million, compared to $211 million in the same period of 2009. Cash flow from operations for the first six months of 2010 increased to $591 million from $399 million in the first six months of 2009. The year-to-date changes in earnings and cash flow from operations were primarily due to the same factors that affected second quarter operating earnings and cash flow from operations.

Operating Earnings
($ millions)



Volumes

Total sales of refined petroleum products averaged 89,000 cubic metres per day during the second quarter of 2010, compared to 33,900 cubic metres per day during the second quarter of 2009. Sales volumes were positively impacted by the merger through Suncor acquiring additional refining assets, national retail and wholesale businesses and an international lubricants business.

Overall, refinery utilization averaged 88% in the second quarter of 2010 on the strength of the Commerce City refinery with utilization of the legacy Suncor refineries averaging 97% consistent with the same period in 2009.

In the first six months of 2010, total sales of refined petroleum products averaged 85,800 cubic metres per day, compared to 32,700 cubic metres per day during the same period in 2009. The increase is primarily due to the same factors affecting the second quarter.

Refinery utilization averaged 90% in the first six months of 2010, with utilization of the legacy Suncor refineries averaging 95% compared to 93% over the same period in 2009.

Margins

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

In the second quarter of 2009, gross margins and as a result, net earnings, benefited from an upward crude profile by $89 million. In the second quarter of 2010, margins were negatively impacted as the crude price exhibited a downward profile. Crude price differentials and 3:2:1 cracking margins improved during the second quarter of 2010, compared to the second quarter of 2009, but were partially offset by the stronger Canadian dollar relative to the U.S. dollar.

Retail has benefited from the merger with increased volumes but the gross petroleum margins were down in the second quarter of 2010, compared to the same period of 2009, due to the change in geographic mix of the expanded network.

Margins during the first six months of 2010 were impacted by primarily the same factors affecting the second quarter.

Operating Expenses

Operating expenses were higher in the second quarter of 2010, compared to the second quarter of 2009, as a result of the larger operations, due to the merger.

During the first six months of 2010, operating expenses were higher when compared to the first six months of 2009. The increase is primarily due to the same reasons affecting the second quarter operating expenses.

Depreciation, Depletion and Amortization

DD&A expenses were higher than the second quarter of 2009 as a result of the larger asset base due to the merger.

The first six months of 2010 had higher DD&A expenses compared to the first six months of 2009 primarily due to the same factors affecting the second quarter.

Planned Maintenance Turnarounds

The Edmonton, Sarnia and Montreal refineries successfully completed turnarounds in the second quarter of 2010. The scope of the Edmonton refinery turnaround was reduced, as a result of integration activities with our Oil Sands operations. Sarnia has further turnaround work planned in the third and fourth quarters of 2010, while the Montreal refinery deferred some turnaround work to the planned fourth quarter turnaround. A significant turnaround is scheduled for the lubricants plant in October 2010. For planned turnarounds, the company enters into transactions to ensure sufficient additional finished product is available to mitigate the impact on customers of lost production.

Risk Factors Affecting Performance

The financial and operating performance of the company's Refining and Marketing business is potentially affected by a number of factors, including, but not limited to, the following:

- 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.

Additional risks, assumptions and uncertainties are discussed in the Legal – Notice Forward-Looking Information section of the MD&A.

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.

	Three months ended June 30		Six months ended June 30	
($ millions, unless otherwise noted)	**2010**	2009	**2010**	2009
Net earnings (loss)				
Renewable energy	**7**	6	**22**	16
Energy trading	**21**	(43)	**10**	(15)
Corporate	**(516)**	242	**(506)**	34
Group eliminations	**2**	(20)	**5**	(31)
	(486)	185	**(469)**	4
Operating earnings (loss)				
Renewable energy	**7**	6	**22**	16
Energy trading	**21**	(43)	**10**	(15)
Corporate	**(168)**	(153)	**(401)**	(192)
Group eliminations	**2**	(20)	**5**	(31)
	(138)	(210)	**(364)**	(222)
Cash flow used in operations	**(196)**	(110)	**(510)**	(52)

Corporate, Energy Trading and Eliminations net loss was $486 million in the second quarter of 2010, compared with net earnings of $185 million in the second quarter of 2009. The decrease was primarily due to a $330 million after-tax foreign exchange loss related to U.S. dollar denominated long-term debt in the second quarter of 2010, compared to an after-tax gain of $405 million in the second quarter of 2009, due to the weakening of the Canadian dollar relative to the U.S. dollar and higher levels of U.S. debt, as a result of the merger.

Cash used in operations was $196 million in the second quarter of 2010, compared to $110 million in the second quarter of 2009. The increase is a result of higher general and administration costs and interest costs from the merger.

Corporate, Energy Trading and Eliminations net loss was $469 million in the first six months of 2010, compared to net earnings of $4 million in the same period of 2009. Operating loss for the first six months of 2010 was $364 million, compared to $222 million in the same period of 2009. Cash used in operations for the first six months of 2010 increased to $510 million from $52 million in the first six months of 2009. The year-to-date changes in operating loss and cash flow used in operations were primarily due to the same factors that impacted second quarter operating loss and cash flows.

Renewable Energy

The company's renewable energy interests include four wind power projects and Canada's largest ethanol plant by production volume. Suncor's four 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. In the second quarter, Suncor received regulatory approval to proceed with developing an additional wind power project in southern Alberta, called Wintering Hills. The Wintering Hills Wind Power project is anticipated to consist of up to 55 turbines, with a generating capacity of 88 megawatts. At peak operation, the project is expected to generate enough clean electricity to power approximately 35,000 Alberta homes and displace a further 200,000 tonnes of CO_2 per year.

The ethanol plant, located in Ontario, has a current capacity of 200 million litres per year, offsetting the equivalent of 300,000 tonnes of CO_2 per year. A $120 million expansion of the plant is currently underway, estimated to be complete by the end of 2010, with a planned doubling of production capacity.

Net earnings of $7 million were contributed from the company's renewable energy operations in the second quarter of 2010, compared to $6 million for the same period in 2009. Earnings increased primarily due to increased sales volumes at the ethanol plant and favorable margins.

The above contains forward-looking information, including reference to: the anticipated number of turbines, electrical capacities and carbon emission offsets in relation to current and proposed wind power projects; and ethanol production capacity, carbon emission offsets and expansion plans for the ethanol plant. See the Legal Notice – Forward-Looking Information section of this MD&A for the material risks and assumptions underlying this forward-looking information.

Energy Trading

Suncor's energy trading activities involve marketing and trading of crude oil, natural gas, refined products and by-products, and the use of financial derivatives. These activities resulted in net earnings of $21 million in the second quarter of 2010, compared to a net loss of $43 million in the second quarter of 2009.

The second quarter of 2010 has been positively impacted by unrealized gains on physical trading inventory. In the second quarter of 2009, results were negatively impacted by unrealized losses on financial contracts.

Corporate and Eliminations

Corporate experienced an operating loss of $168 million in the second quarter of 2010, compared to an operating loss of $153 million in the second quarter of 2009. The increase was primarily the result of increased net interest expense, due to additional debt acquired through the merger.

Group eliminations reflects the elimination of profit on crude oil sales between Oil Sands and Refining and Marketing and East Coast Canada and Refining and Marketing, where this crude oil still resides in Refining and Marketing's inventories. During the second quarter of 2010, $2 million of profits previously eliminated were recovered, compared to profits of $20 million that were eliminated in the second quarter of 2009.

CASH INCOME TAXES

The company estimates that it will have cash income taxes of approximately $1 billion to $1.1 billion during 2010. Cash income taxes are sensitive to crude oil and natural gas commodity price volatility and the timing of deductibility of capital expenditures for income tax purposes, among other things. This estimate is based on the following assumptions: current forecasts of production, capital and operating costs and the commodity prices and exchange rates described in the royalty estimate tables for the Oil Sands and International and Offshore segments' and assumes there are no changes to any of the current applicable income tax regimes. The company's outlook on cash income taxes is a forward-looking information and users of this information are cautioned that actual cash income taxes may vary materially from this outlook. For further information related to risk factors that could affect this estimate, refer to pages 54 to 62 of the 2009 AIF, which section is incorporated herein by reference.

FINANCIAL CONDITION AND LIQUIDITY

($ millions, except ratios)	**June 30 2010**	December 31 2009
Working capital (deficit)(1)	**651**	(315)
Short-term debt	**2**	2
Current portion of long-term debt	**21**	25
Long-term debt	**13 609**	13 855
Total debt	**13 632**	13 882
Less: Cash and cash equivalents	**455**	505
Net debt	**13 177**	13 377
Shareholders' equity	**34 623**	34 111
Total capitalization (total debt & shareholders' equity)	**48 255**	47 993
Total debt to debt plus shareholders' equity (%)(2)	**28**	29

	Twelve months ended June 30 **2010**	2009
ROCE (%)(3)	**7.0**	7.3
ROCE (%)(4)	**5.1**	5.0
Net debt to cash flow from operations (times)(5)	**2.9**	3.7
Interest coverage on long-term debt (times)		
Net earnings(6)	**6.1**	1.5
Cash flow from operations(7)	**9.0**	7.0

(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 for the twelve-month period then ended.

(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.

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 June 30, 2010, Suncor's net debt was $13.2 billion, compared to $13.4 billion at December 31, 2009. Undrawn lines of credit at June 30, 2010 were approximately $4.4 billion compared to $4.2 billion at December 31, 2009. During the second quarter of 2010, the company reduced its committed bilateral credit facility from $15 million to $4 million.

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 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 June 30, 2010, total debt to total capitalization was 28% (December 31, 2009 – 29%). The company is also currently in compliance with all operating covenants.

The preceding paragraphs contain forward-looking information regarding our liquidity and capital resources and our ability to comply with financial and operating covenants related to our public market and bank debt. See the Legal – Notice Forward-Looking Information section of this MD&A for the material risks and assumptions underlying this forward-looking information.

Outstanding Shares

At June 30, 2010	thousands
Common shares	1 562 168
Common share options – total	72 201

Credit Ratings

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 2009 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.

Significant Capital Project Update

Suncor spent $1.47 billion on capital and exploration in the second quarter of 2010, bringing the year-to-date spend to $2.52 billion, out of a Board approved budget of $5.50 billion for 2010. A summary of the progress on significant projects under construction to support both growth and sustaining needs is provided below. All projects listed below have received Board approval. The estimates and target completion dates do not include project commissioning and start-up.

Project	Business Segment	Plan	Cost Estimate $ millions (1)	Estimate % Accuracy (1)	Spent to date	Target completion date
Ebla gas project	International and Offshore	Development of gas fields and construction of gas treatment plant	1 196	N/A	1 125	Completed in Q2 2010 (2)
Buzzard enhancement project (3)	International and Offshore	Installation of equipment to handle high sulphur content	339	+15/−10	200	Q4 2010
Firebag Stage 3	Oil Sands	Expansion is expected to increase bitumen supply	3 638	+10/−10	3 323	Q2 2011
Naphtha unit	Oil Sands	Increases sweet product mix	850	+5/−1	703	Q4 2011 (4)
North Amethyst (3)	International and Offshore	Extension to the White Rose field involving sub-sea tie-in	490	+10/−5	335	2012 (5)

(1) Cost estimates and estimate accuracy reflect budgets approved by Suncor's Board of Directors.

(2) Commercial production began in April 2010.

(3) Amounts represent Suncor's net share in the project.

(4) Previously targeted to be completed in the third quarter of 2011. This has been delayed due to resources being deployed to the upgrader rebuilds in the first quarter of 2010. The cost and schedule of the project is currently under review. Management expects the cost estimate and schedule to change and plans to provide an update to the Board for approval at a future date.

(5) First oil was achieved in the second quarter of 2010. Facility and sub-sea tie-in work is complete and all future spending is related to drilling activity.

The company continues to incur costs related to placing certain growth projects into "safe mode" due to market conditions last year. Safe mode is 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 $33 million were incurred in the second quarter of 2010 with a year to date total of $73 million. Safe mode costs of approximately $150 million to $200 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 preceding paragraphs contain forward-looking information and users of this information are cautioned that the actual timing, amount of the final capital expenditures and expected results, including target completion dates, for each of these projects may vary from the plans disclosed.

The material factors and assumptions used to develop target completion dates and cost estimates are: current capital spending plans, the current status of procurement, design and engineering phases of the project; updates from third parties on delivery of goods and services associated with the project; and estimates from major projects teams on completion of future phases of the project. We have assumed that commitments from third parties will be honoured and that material delays and increased costs related to the risk factors referred to above will not be encountered. Users are referred to the Legal Notice – Forward-Looking Information section of this MD&A for the material risks and assumptions underlying this forward-looking information.

For a list of the additional risk factors that could cause actual timing, amount of the final capital expenditures and expected results to differ materially, please see the section entitled "Risk Factors" starting on page 54 of Suncor's 2009 AIF, which section of the 2009 AIF is incorporated herein by reference.

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)	**June 30 2010**	December 31 2009
Assets	**132**	213
Liabilities	**(238)**	(572)
Net derivative financial instruments	**(106)**	(359)

For further details on the company's derivative financial instruments at June 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 6 to the 2009 Audited Consolidated Financial Statements, which is incorporated herein by reference.

Risks Associated with Derivative Financial Instruments

Our 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.

We may be exposed to certain losses in the event that the counterparties to derivative financial instruments are unable to meet the terms of the contracts. We minimize this risk 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. Our exposure is limited to those counterparties holding derivative contracts with net positive fair values at the reporting date.

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 Risk Factors Affecting Performance for each of Suncor's business segments. 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)

As of June 30, 2010, Suncor has made significant progress on its IFRS project and continues to be on target to meet the changeover date. The following is a status update of the company's conversion project. A description of major accounting policy choices are outlined on pages 31 to 32 of Suncor's 2009 Annual Report. The accounting policy choices previously communicated should not be regarded as a complete list of changes that will result from the transition to IFRS. It is intended to highlight those areas the company believes to be most significant. However, analysis of changes will be ongoing throughout 2010. Note that new and revised IFRS developments will be monitored throughout the project but may result in changes to the project activities.

IFRS Conversion Project

Key Activity	Key Milestones	Status
Financial Statement Preparation: – Identify differences in Canadian GAAP/IFRS accounting policies. – Select Suncor's ongoing IFRS policies – Develop financial statement format. – Quantify effects of change in initial IFRS disclosure and 2010 financial statements.	Senior management and steering committee sign-off for all key IFRS accounting policy choices to continue in 2010. Finalize draft financial statement format during 2010.	Presented draft IFRS January 1, 2010 opening Balance Sheet to the Steering and Audit Committee. The opening balance sheet has been provided to the company's external auditors for their consideration. Draft first quarter 2010 financial statements, pro-forma financial statements and disclosures substantially completed. Review by senior management and the company's auditors underway. To be presented to the Steering and Audit Committee in the third quarter of 2010.
Training: Define and introduce appropriate level of IFRS expertise for each of the following: – Financial reporting group and operating accounting staff. – Suncor management. – Audit Committee.	Financial reporting group and operating accounting staff training to continue during 2010. Additional training will occur throughout the project as needs are reassessed. Suncor management and Audit Committee training to continue during 2010.	Training and communication sessions continued for senior management, Financial Reporting and key individuals within the Business, including IFRS refresh sessions (IFRS technical and status updates). Facilitation of knowledge transfer sessions targeted for the third quarter of 2010. Regular reporting and training has continued for the Company's senior executive management and the Audit Committee.
Infrastructure: Confirm that business processes and systems are IFRS compliant, including: – Program upgrades/changes. – Gathering data for disclosures.	Confirm that systems can address 2010 dual reporting requirements and identify areas requiring change. Confirmation that business processes and systems are IFRS compliant will occur throughout the project.	Completed testing of dual reporting IFRS IT solution and development of the 2011 conversion plan. IFRS data capture to commence in the third quarter of 2010. Testing of 2011 conversion plan targeted for the third quarter of 2010. Implementation of business changes is ongoing.
Control Environment: – For all accounting policy changes identified, assess control design and effectiveness implications. – Implement appropriate changes.	All key control and design effectiveness implications are being assessed as part of the key IFRS differences and accounting policy choices throughout 2010.	Analysis to date continues to support preliminary assessment that no material changes will be required to internal and disclosure controls over financial reporting. Internal control documentation related to the preparation of 2010 IFRS financial statements including controls related to completeness of adjustments will be completed in the third quarter of 2010.

Control Environment

Based on their evaluation as of June 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 June 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 June 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 completed by the end of 2010.

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.

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 it provides better comparability between periods. All reconciling items are presented on an after-tax basis.

A reconciliation of after-tax net earnings to after-tax operating earnings is presented in the following table:

Three months ended June 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 as reported	**517**	(307)	**(68)**	(23)	**217**	—	**138**	99	**(486)**	185	**318**	(46)
Change in fair value of commodity derivatives used for risk management (1)	**(149)**	442	**—**	—	**—**	—	**—**	—	**—**	—	**(149)**	442
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**—**	—	**—**	—	**—**	—	**—**	—	**330**	(405)	**330**	(405)
Mark-to-market valuation of stock-based compensation	**(2)**	6	**(1)**	—	**—**	—	**1**	1	**(5)**	10	**(7)**	17
Project start-up costs	**11**	7	**—**	—	**1**	—	**—**	—	**—**	—	**12**	7
Costs related to deferral of growth projects	**24**	28	**—**	—	**—**	—	**—**	—	**—**	—	**24**	28
Merger and integration costs	**—**	—	**—**	—	**—**	—	**—**	—	**23**	—	**23**	—
Losses (gains) on significant disposals	**2**	—	**(1)**	—	**—**	—	**(4)**	—	**—**	—	**(3)**	—
Impairment and write-offs (2)	**141**	—	**15**	—	**—**	—	**—**	—	**—**	—	**156**	—
Adjustments to provisions for assets acquired through the merger (3)	**—**	—	**18**	—	**28**	—	**(22)**	—	**—**	—	**24**	—
Operating earnings (loss) from continuing operations	**544**	176	**(37)**	(23)	**246**	—	**113**	100	**(138)**	(210)	**728**	43
Net earnings from discontinued operations as reported	**—**	—	**113**	(5)	**49**	—	**—**	—	**—**	—	**162**	(5)
Gains on disposals of discontinued operations	**—**	—	**(109)**	—	**—**	—	**—**	—	**—**	—	**(109)**	—
Operating earnings (loss) from total operations	**544**	176	**(33)**	(28)	**295**	—	**113**	100	**(138)**	(210)	**781**	38

Six months ended June 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 as reported	**593**	(417)	**(45)**	(33)	**426**	—	**277**	211	**(469)**	4	**782**	(235)
Change in fair value of commodity derivatives used for risk management (1)	**(157)**	745	**—**	—	**—**	—	**—**	—	**—**	—	**(157)**	745
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**—**	—	**—**	—	**—**	—	**—**	—	**100**	(257)	**100**	(257)
Mark-to-market valuation of stock-based compensation	**(4)**	7	**(8)**	—	**(5)**	—	**(7)**	—	**(34)**	31	**(58)**	38
Project start-up costs	**19**	18	**—**	—	**2**	—	**—**	—	**—**	—	**21**	18
Costs related to deferral of growth projects	**54**	151	**—**	—	**—**	—	**—**	—	**—**	—	**54**	151
Merger and integration costs	**—**	—	**—**	—	**—**	—	**—**	—	**39**	—	**39**	—
Gains (losses) on significant disposals	**2**	—	**(28)**	—	**—**	—	**(4)**	—	**—**	—	**(30)**	—
Impairment and write-offs (2)	**141**	—	**15**	—	**—**	—	**—**	—	**—**	—	**156**	—
Adjustments to provisions for assets acquired through the merger (3),	**—**	—	**18**	—	**28**	—	**(22)**	—	**—**	—	**24**	—
Operating earnings (loss) from continuing operations	**648**	504	**(48)**	(33)	**451**	—	**244**	211	**(364)**	(222)	**931**	460
Net earnings from discontinued operations as reported	**—**	—	**311**	(5)	**103**	—	**—**	—	**—**	—	**414**	(5)
Gains on disposals of discontinued operations	**—**	—	**(277)**	—	**—**	—	**—**	—	**—**	—	**(277)**	—
Operating earnings (loss) from total operations	**648**	504	**(14)**	(38)	**554**	—	**244**	211	**(364)**	(222)	**1 068**	455

(1) 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 which are not adjusted for.

(2) For more information on impairments and write-offs refer to note 5 of the unaudited Interim Consolidated Financial Statements.

(3) Adjustments were 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 during the second quarter of 2010.

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 June 30, 2010 interim basis, please refer to the Highlights Supplement.

Cash Flow from Operations

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

Three months ended June 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	**517**	(307)	**(68)**	(23)	**217**	—	**138**	99	**(486)**	185	**318**	(46)
Adjustments for:												
Depreciation, depletion and amortization	**454**	197	**185**	39	**273**	—	**114**	54	**24**	6	**1 050**	296
Future income taxes	**171**	(309)	**(30)**	(3)	**3**	—	**21**	40	**(89)**	(1)	**76**	(273)
Accretion of asset retirement obligations	**30**	25	**7**	2	**7**	—	**1**	1	**—**	—	**45**	28
Unrealized (gain) loss on translation of U.S. dollar denominated long-term debt	**—**	—	**—**	—	**—**	—	**—**	—	**376**	(405)	**376**	(405)
Change in fair value of derivative contracts	**(144)**	644	**—**	—	**—**	—	**(1)**	(17)	**(28)**	88	**(173)**	715
Loss (gain) on disposal of assets	**2**	—	**(1)**	(15)	**—**	—	**(6)**	20	**1**	—	**(4)**	5
Stock-based compensation	**5**	21	**(3)**	1	**(8)**	—	**3**	5	**—**	21	**(3)**	48
Other	**(102)**	(97)	**(9)**	1	**8**	—	**(7)**	(13)	**6**	(4)	**(104)**	(113)
Exploration expenses	**—**	—	**1**	31	**17**	—	**—**	—	**—**	—	**18**	31
Total cash flow from (used in) operations from continuing operations	**933**	174	**82**	33	**517**	—	**263**	189	**(196)**	(110)	**1 599**	286
Total cash flow from (used in) operations from discontinued operations	**—**	—	**38**	9	**121**	—	**—**	—	**—**	—	**159**	9
Total cash flow from (used in) operations	**933**	174	**120**	42	**638**	—	**263**	189	**(196)**	(110)	**1 758**	295

Six months ended June 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	**593**	(417)	**(45)**	(33)	**426**	—	**277**	211	**(469)**	4	**782**	(235)
Adjustments for:												
Depreciation, depletion and amortization	**723**	380	**317**	77	**563**	—	**232**	107	**34**	16	**1 869**	580
Future income taxes	**198**	(531)	**(22)**	4	**32**	—	**79**	81	**(118)**	31	**169**	(415)
Accretion of asset retirement obligations	**60**	52	**13**	3	**13**	—	**2**	1	**—**	—	**88**	56
Unrealized (gain) loss on translation of U.S. dollar denominated long-term debt	**—**	—	**—**	—	**—**	—	**—**	—	**116**	(257)	**116**	(257)
Change in fair value of derivative contracts	**(211)**	1 290	**—**	—	**—**	—	**(1)**	(23)	**(41)**	105	**(253)**	1 372
Loss (gain) on disposal of assets	**11**	17	**(37)**	(15)	**—**	—	**(3)**	20	**1**	—	**(28)**	22
Stock-based compensation	**13**	37	**(12)**	2	**(6)**	—	**(6)**	7	**(69)**	57	**(80)**	103
Other	**(192)**	(174)	**(13)**	(1)	**10**	—	**11**	(5)	**36**	(8)	**(148)**	(188)
Exploration expenses	**—**	—	**13**	31	**21**	—	**—**	—	**—**	—	**34**	31
Total cash flow from (used in) operations from continuing operations	**1 195**	654	**214**	68	**1 059**	—	**591**	399	**(510)**	(52)	**2 549**	1 069
Total cash flow (used in) operations from discontinuing operations	**—**	—	**103**	27	**230**	—	**—**	—	**—**	—	**333**	27
Total cash flow from (used in) operations	**1 195**	654	**317**	95	**1 289**	—	**591**	399	**(510)**	(52)	**2 882**	1 096

Cash Operating Costs

The following tables outline the reconciliation of Oil Sands expenses included in the Schedules of Segmented Data in the June 30, 2010 unaudited Interim Consolidated Financial Statements to total and per barrel cash operating costs, total cash operating costs and total operating costs:

Oil Sands Operating Costs – Total Operations (1)

	Three months ended June 30				Six months ended June 30			
	2010		2009		**2010**		2009	
	$ millions	$/barrel	$ millions	$/barrel	$ millions	$/barrel	$ millions	$/barrel
Operating, selling and general expenses	**997**		1 058		**2 115**		1 996	
(Less) add: Natural gas costs, inventory changes, stock-based compensation, and other	**16**		(216)		**(105)**		(213)	
(Less) Safe mode costs	**(33)**		(40)		**(73)**		(215)	
(Less) Non-monetary transactions	**(19)**		(16)		**(33)**		(42)	
(Less) Syncrude-related operating, selling and general expenses	**(112)**		—		**(237)**		—	
Accretion of asset retirement obligations	**30**		25		**60**		52	
Cash costs	**879**	**32.70**	811	29.65	**1 727**	**38.25**	1 578	30.15
Natural gas	**69**	**2.55**	45	1.65	**167**	**3.70**	120	2.30
Imported bitumen (excluding other reported product purchases)	**18**	**0.65**	1	—	**71**	**1.55**	2	0.05
Cash operating costs	**966**	**35.90**	857	31.30	**1 965**	**43.50**	1 700	32.50
Project start-up costs	**14**	**0.55**	10	0.35	**24**	**0.55**	26	0.50
Total cash operating costs	**980**	**36.45**	867	31.65	**1 989**	**44.05**	1 726	33.00
Depreciation, depletion and amortization	**413**	**15.35**	197	7.20	**643**	**14.25**	380	7.25
Total operating costs	**1 393**	**51.80**	1 064	38.85	**2 632**	**58.30**	2 106	40.25
Production excluding Syncrude (thousands of barrels per day)	**295.5**		301.0		**249.3**		289.0	

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

Legal Notice – 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. These 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.

Suncor's outlook includes a production range based on our current expectations, estimates, projections and assumptions. Uncertainties in the estimating process and the impact of future events may cause actual results to differ, in some cases materially, from our estimates. Assumptions are based on management's experience and perception of historical trends, current conditions, anticipated future developments and other factors believed to be relevant. For a description of assumptions and risk factors specifically related to the 2010 outlook, see section entitled "Risk Factors Affecting Performance" on page six of our second quarter 2010 Report to Shareholders, which section of the second quarter 2010 Report to Shareholders is incorporated herein by reference.

The risks, uncertainties and other factors that could influence actual results include but are not limited to, market instability affecting Suncor's ability to borrow in the capital debt markets at acceptable rates; availability of third-party bitumen; success of hedging strategies, maintaining a desirable debt to cash flow ratio; changes in the general economic, market and business conditions; fluctuations in supply and demand for Suncor's products; commodity prices, interest rates and currency exchange rates; 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; 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); uncertainties relating to the ability of closing conditions to be met in respect of any planned divestitures in a timely manner, or at all; political, economic and socio-economic risk associated with foreign operations (including OPEC production quotas); 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 the other entity. 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 June 30		
Cash flow from operations (1)	**1.13**	0.31
For the six months ended June 30		
Cash flow from operations (1)	**1.85**	1.17
Ratios		
For the twelve months ended June 30		
Return on capital employed (%) (2)	**7.0**	7.3
Return on capital employed (%) (3)	**5.1**	5.0
Net debt to cash flow from operations (times) (4)	**2.9**	3.7
Interest coverage on long-term debt (times)		
Net earnings (5)	**6.1**	1.5
Cash flow from operations (6)	**9.0**	7.0
As at June 30		
Debt to debt plus shareholders' equity (%) (7)	**28**	40
Common Share Information		
As at June 30		
Share price at end of trading		
Toronto Stock Exchange – Cdn$	**31.33**	35.37
New York Stock Exchange – US$	**29.44**	30.34
Common share options outstanding (thousands)	**72 201**	46 127
For the six months ended June 30		
Average number outstanding, weighted monthly (thousands)	**1 561 199**	936 598

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 – $2,417 million; 2009 – $1,023 million) adjusted for after-tax financing income (2010 – $165 million; 2009 – expense of $663 million) divided by average capital employed (2010 – $34,340 million; 2009 – $14,047 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. Return on capital employed (ROCE) for Suncor operating segments as presented in the Quarterly Operating Summary is calculated in a manner consistent with consolidated ROCE.

(3) If capital employed were to include capitalized costs related to major projects in progress (average capital employed including major projects in progress: 2010 – $47,413 million; 2009 – $20,597 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. The increase in debt levels as a result of the merger with Petro-Canada has caused our net debt to cash flow from operations measure to increase significantly, as the calculation only includes eleven months of cash flow from operations relating to legacy Petro-Canada operations.

(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					Six months ended		Twelve months ended
	June 30 2010	Mar 31 2010	Dec 31 2009	Sept 30 2009	June 30 2009	**June 30 2010**	June 30 2009	Dec 31 2009
OIL SANDS								
Production [a]								
Total production (excluding Syncrude)	**295.5**	202.3	278.9	305.3	301.0	**249.3**	289.0	290.6
Firebag [k]	**55.7**	55.7	51.1	54.3	48.3	**55.7**	45.4	49.1
MacKay River [k]	**32.5**	31.8	31.7	26.5***	—	**32.1**	—	29.7***
Syncrude	**38.9**	32.3	39.3	37.4***	—	**35.6**	—	38.5***
Sales [a] (excluding Syncrude)								
Light sweet crude oil	**99.0**	61.0	100.8	89.6	99.4	**80.1**	104.1	99.6
Diesel	**30.7**	12.9	31.4	36.9	25.3	**21.8**	24.1	29.1
Light sour crude oil	**143.1**	80.5	142.4	146.8	150.5	**112.0**	126.7	135.7
Bitumen	**37.4**	42.3	13.0	14.3	10.5	**39.9**	9.8	11.8
Total sales	**310.2**	196.7	287.6	287.6	285.7	**253.8**	264.7	276.2
Average sales price [1],[b] (excluding Syncrude)								
Light sweet crude oil*	**77.55**	80.84	77.71	71.99	65.83	**78.79**	60.04	67.26
Other (diesel, light sour crude oil and bitumen)*	**68.53**	69.53	72.93	67.51	62.71	**68.92**	56.93	64.18
Total*	**71.41**	73.03	74.61	68.91	63.79	**72.04**	58.15	65.29
Total	**69.79**	70.21	65.42	62.01	59.34	**69.95**	59.39	61.66
Syncrude average sales price [1],[b]	**77.32**	83.21	78.81	75.17	—	**80.26**	—	77.36
Cash operating costs and Total operating costs – Total operations (excluding Syncrude) [c]								
Cash costs	**32.70**	46.50	35.10	30.65	29.65	**38.25**	30.15	31.50
Natural gas	**2.55**	5.40	3.40	1.55	1.65	**3.70**	2.30	2.40
Imported bitumen	**0.65**	2.95	0.20	0.05	—	**1.55**	0.05	0.05
Cash operating costs [2]	**35.90**	54.85	38.70	32.25	31.30	**43.50**	32.50	33.95
Project start-up costs	**0.55**	0.55	0.50	0.45	0.35	**0.55**	0.50	0.45
Total cash operating costs [3]	**36.45**	55.40	39.20	32.70	31.65	**44.05**	33.00	34.40
Depreciation, depletion and amortization	**15.35**	12.65	10.00	7.60	7.20	**14.25**	7.25	8.00
Total operating costs [4]	**51.80**	68.05	49.20	40.30	38.85	**58.30**	40.25	42.40
Cash operating costs and Total operating costs – Syncrude [c]****								
Cash costs	**28.75**	39.60	29.65	29.50	—	**33.65**	—	29.60
Natural gas	**2.85**	4.50	3.45	2.10	—	**3.60**	—	2.90
Cash operating costs [2]	**31.60**	44.10	33.10	31.60	—	**37.25**	—	32.50
Project start-up costs	**—**	—	—	—	—	**—**	—	—
Total cash operating costs [3]	**31.60**	44.10	33.10	31.60	—	**37.25**	—	32.50
Depreciation, depletion and amortization	**11.35**	13.70	11.80	12.70	—	**12.40**	—	12.15
Total operating costs [4]	**42.95**	57.80	44.90	44.30	—	**49.65**	—	44.65
Cash operating costs and Total operating costs – In situ bitumen production only [c]								
Cash costs	**13.65**	12.30	14.25	13.25	16.40	**13.00**	15.85	14.55
Natural gas	**5.05**	7.05	6.05	4.30	5.30	**6.05**	6.50	5.70
Cash operating costs [5]	**18.70**	19.35	20.30	17.55	21.70	**19.05**	22.35	20.25
Project start-up costs	**1.45**	0.95	1.35	0.65	1.45	**1.20**	1.85	1.35
Total cash operating costs [6]	**20.15**	20.30	21.65	18.20	23.15	**20.25**	24.20	21.60
Depreciation, depletion and amortization	**4.70**	5.05	6.65	5.95	6.00	**4.85**	6.45	6.35
Total operating costs [7]	**24.85**	25.35	28.30	24.15	29.15	**25.10**	30.65	27.95
Ending capital employed excluding major projects in progress [i]	**17 989**	17 829	16 141	14 833	10 008			
(for the twelve months ended)								
Return on capital employed [j]	**9.1**	5.2	4.2	8.4	11.1			
Return on capital employed [j]**	**5.7**	3.1	2.5	4.9	6.5			

Quarterly Operating Summary (continued)

(unaudited)

	Three months ended					Six months ended		Twelve months ended
	June 30 2010	Mar 31 2010	Dec 31 2009	Sept 30 2009	June 30 2009	**June 30 2010**	June 30 2009	Dec 31 2009
NATURAL GAS								
Gross production								
Natural gas [d]								
Continuing operations	**398**	419	419	334	145	**408**	143	272
Discontinued operations	**138**	230	255	183	47	**184**	53	126
Natural gas liquids and crude oil [a]								
Continuing operations	**5.5**	6.2	6.1	4.7	1.0	**5.8**	1.0	3.6
Discontinued operations	**2.8**	7.8	8.9	6.0	2.2	**5.3**	2.2	4.5
Total gross production [f]								
Continuing operations	**431**	456	456	362	151	**443**	149	293
Discontinued operations	**155**	277	308	219	60	**216**	66	153
Average sales price from continuing operations [1]								
Natural gas [g]	**3.40**	5.34	3.92	2.70	3.26	**4.38**	4.32	3.49
Natural gas [g]*	**3.40**	5.34	3.91	2.68	3.23	**4.38**	4.30	3.48
Natural gas liquids and crude oil [b]	**81.68**	74.71	65.74	58.31	40.04	**77.13**	42.50	53.98
Ending capital employed [i]	**2 155**	2 489	3 349	3 632	1 200			
(for the twelve months ended)								
Return on capital employed [j]	**3.4**	1.2	(8.4)	(9.6)	(1.7)			

Quarterly Operating Summary (continued)

(unaudited)

	Three months ended					Six months ended		Twelve months ended
	June 30 2010	Mar 31 2010	Dec 31 2009	Sept 30 2009***	June 30 2009	**June 30 2010**	June 30 2009	Dec 31 2009***
INTERNATIONAL AND OFFSHORE								
East Coast Canada								
Production (a)								
Terra Nova	**27.2**	29.6	24.0	16.0	—	**28.4**	—	20.8
Hibernia	**30.1**	30.2	26.3	28.5	—	**30.2**	—	27.2
White Rose	**13.3**	14.8	13.3	5.1	—	**14.0**	—	10.0
Total production	**70.6**	74.6	63.6	49.6	—	**72.6**	—	58.0
Average sales price (1)(b)	**76.88**	78.69	77.71	75.22	—	**77.80**	—	76.86
International								
Production (e)								
North Sea								
Buzzard	**49.3**	58.6	59.9	29.4	—	**53.9**	—	47.8
Production from discontinued operations	**22.7**	27.5	31.1	25.2	—	**25.2**	—	28.7
Total North Sea	**72.0**	86.1	91.0	54.6	—	**79.1**	—	76.5
Other International								
Libya	**35.4**	35.4	26.0	42.7	—	**35.4**	—	32.6
Syria	**12.8**	—	—	—	—	**6.4**	—	—
Production from discontinued operations	**11.1**	11.7	12.0	11.3	—	**11.4**	—	11.7
Total Other International	**59.3**	47.1	38.0	54.0	—	**53.2**	—	44.3
Total production	**131.3**	133.2	129.0	108.6	—	**132.3**	—	120.8
Average sales price from continuing operations (1) **– Buzzard** (l)	**80.35**	72.36	68.71	72.02	—	**77.03**	—	69.53
Average sales price from continuing operations (1) **– Other International** (l)	**76.14**	73.40	79.18	75.60	—	**76.96**	—	78.05
Ending capital employed excluding major projects in progress (i)	**5 976**	4 570	4 970	4 903	—			
(for the twelve months ended)								
Return on capital employed (j)	**16.2**	16.5	11.2	9.3	—			
Return on capital employed (j)**	**10.5**	10.4	7.1	5.9	—			

Production from Syria averaged 15.9 thousands of barrels of oil equivalent per day from the date commercial production commenced on April 19, 2010.

Quarterly Operating Summary (continued)

(unaudited)

	Three months ended					Six months ended		Twelve months ended
	June 30 2010	Mar 31 2010	Dec 31 2009	Sept 30 2009	June 30 2009	**June 30 2010**	June 30 2009	Dec 31 2009
REFINING & MARKETING								
Eastern North America								
Refined product sales (h)								
Transportation fuels								
Gasoline	**21.4**	20.2	23.0	18.3	8.7	**20.7**	8.4	14.6
Distillate	**15.7**	11.4	13.9	10.3	5.4	**13.4**	5.3	8.8
Total transportation fuel sales	**37.1**	31.6	36.9	28.6	14.1	**34.1**	13.7	23.4
Petrochemicals	**2.8**	2.2	1.2	1.7	1.0	**2.6**	1.0	0.8
Asphalt	**2.9**	1.8	2.0	2.4	0.7	**2.3**	0.7	1.5
Other	**4.4**	5.3	1.9	3.0	1.0	**5.3**	0.8	2.0
Total refined product sales	**47.2**	40.9	42.0	35.7	16.8	**44.3**	16.2	27.7
Crude oil supply and refining								
Processed at refineries (h)	**30.6**	31.0	28.3	25.5	11.8	**30.8**	11.6	29.6
Utilization of refining capacity (j)	**90**	91	83	94	87	**90**	86	87
Western North America								
Refined product sales (h)								
Transportation fuels								
Gasoline	**19.2**	18.1	18.4	16.1	8.9	**18.7**	8.6	13.0
Distillate	**16.3**	17.0	15.6	11.8	5.0	**16.7**	5.2	9.5
Total transportation fuel sales	**35.5**	35.1	34.0	27.9	13.9	**35.4**	13.8	22.5
Asphalt	**1.5**	1.2	0.9	1.7	1.4	**1.4**	1.3	1.3
Other	**4.8**	5.0	6.0	4.6	1.8	**4.7**	1.4	3.4
Total refined product sales	**41.8**	41.3	40.9	34.2	17.1	**41.5**	16.5	27.2
Crude oil supply and refining								
Processed at refineries (h)	**31.7**	33.5	33.4	27.8	15.6	**32.6**	14.9	33.6
Utilization of refining capacity (j)	**87**	92	96	100	106	**90**	101	97
Ending capital employed excluding major projects in progress (i)	**7 671**	7 794	7 727	7 730	2 573			
(for the twelve months ended)								
Return on capital employed (j)	**5.8**	6.6	8.7	2.6	0.7			

Quarterly Operating Summary (continued)

(unaudited)

	Three months ended					Six months ended		Twelve months ended
	June 30 2010	Mar 31 2010	Dec 31 2009	Sept 30 2009	June 30 2009	**June 30 2010**	June 30 2009	Dec 31 2009
NETBACKS – Continuing Operations								
Natural Gas (g)								
Average price realized (8)	**5.06**	6.23	5.02	3.66	3.56	**5.63**	4.66	4.29
Royalties	**(0.06)**	(0.91)	(0.71)	0.03	0.88	**(0.49)**	(0.07)	(0.29)
Operating costs	**(2.10)**	(1.67)	(1.88)	(1.79)	(1.55)	**(1.87)**	(1.71)	(1.73)
Operating netback	**2.90**	3.65	2.43	1.90	2.89	**3.27**	2.88	2.27
Depreciation, depletion and amortization	**(4.88)**	(3.36)	(2.84)	(3.06)	(2.95)	**(4.08)**	(2.97)	(2.82)
Administrative expenses and other	**(0.48)**	0.40	(1.67)	(2.34)	(2.30)	**(0.04)**	(1.75)	(1.82)
Earnings before income taxes	**(2.46)**	0.69	(2.08)	(3.50)	(2.36)	**(0.85)**	(1.84)	(2.37)
International and Offshore								
East Coast Canada (b)								
Average price realized (8)	**78.99**	80.79	79.69	77.85	—	**79.92**	—	79.07
Royalties	**(28.45)**	(28.78)	(25.26)	(21.02)	—	**(28.62)**	—	(23.82)
Operating costs	**(8.65)**	(8.92)	(7.89)	(13.36)	—	**(8.78)**	—	(9.76)
Operating netback	**41.89**	43.09	46.54	43.47	—	**42.52**	—	45.49
Depreciation, depletion and amortization	**(24.08)**	(23.38)	(26.56)	(17.48)	—	**(23.72)**	—	(23.47)
Administrative expenses and other	**1.37**	0.31	(1.33)	(0.52)	—	**0.83**	—	(1.05)
Earnings before income taxes	**19.18**	20.02	18.65	25.47	—	**19.63**	—	20.97
North Sea – Buzzard (b)								
Average price realized (8)	**80.35**	74.19	70.38	75.49	—	**77.03**	—	71.64
Operating costs	**(5.35)**	(4.92)	(4.57)	(6.29)	—	**(5.12)**	—	(4.99)
Operating netback	**75.00**	69.27	65.81	69.20	—	**71.91**	—	66.65
Depreciation, depletion and amortization	**(21.83)**	(22.76)	(25.24)	(18.54)	—	**(22.33)**	—	(23.60)
Administrative expenses and other	**(3.72)**	(3.35)	(2.20)	(2.83)	—	**(3.52)**	—	(2.36)
Earnings before income taxes	**49.45**	43.16	38.37	47.83	—	**46.06**	—	40.69
Other International (l)								
Average price realized (8)	**76.61**	73.92	79.97	76.02	—	**77.45**	—	78.19
Royalties	**(36.99)**	(43.28)	(32.12)	(46.46)	—	**(41.60)**	—	(39.88)
Operating costs	**(7.87)**	(3.81)	(6.03)	(2.21)	—	**(6.16)**	—	(4.05)
Operating netback	**31.75**	26.83	41.82	27.35	—	**29.69**	—	34.26
Depreciation, depletion and amortization	**(4.64)**	(4.29)	(6.39)	(1.54)	—	**(4.49)**	—	(3.86)
Administrative expenses and other	**(5.09)**	(6.63)	(11.46)	(5.98)	—	**(5.74)**	—	(8.60)
Earnings before income taxes	**22.02**	15.91	23.97	19.83	—	**19.46**	—	21.80

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 operating earnings, 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 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.

(a) thousands of barrels per day	(e) thousands of barrels of oil equivalent per day	(i) $ millions
(b) dollars per barrel	(f) millions of cubic feet equivalent per day	(j) percentage
(c) dollars per barrel rounded to the nearest $0.05	(g) dollars per thousand cubic feet equivalent	(k) thousands of barrels of bitumen per day
(d) millions of cubic feet per day	(h) thousands of cubic metres 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 June 30 2010	2009	Six months ended June 30 2010	2009
Revenues				
Operating revenues	**8 340**	2 752	**15 402**	5 212
Less: Royalties	**(499)**	(125)	**(941)**	(146)
Operating revenues (net of royalties)	**7 841**	2 627	**14 461**	5 066
Energy supply and trading activities	**1 103**	2 120	**1 447**	4 288
Interest and other income	**61**	1	**69**	1
	9 005	4 748	**15 977**	9 355
Expenses				
Purchases of crude oil and products	**3 727**	1 293	**6 957**	2 218
Operating, selling and general	**1 839**	1 329	**3 645**	2 520
Energy supply and trading activities	**989**	2 165	**1 351**	4 285
Transportation	**163**	63	**306**	124
Depreciation, depletion and amortization (note 5)	**1 050**	296	**1 869**	580
Accretion of asset retirement obligations	**45**	28	**88**	56
Exploration	**47**	32	**93**	39
Loss (gain) on disposal of assets	**(4)**	5	**(28)**	22
Project start-up costs	**15**	10	**27**	26
Financing expenses (income) (note 7)	**478**	(268)	**288**	(69)
	8 349	4 953	**14 596**	9 801
Earnings (Loss) Before Income Taxes	**656**	(205)	**1 381**	(446)
Provisions for (Recovery of) Income Taxes (note 8)				
Current	**262**	114	**430**	204
Future	**76**	(273)	**169**	(415)
	338	(159)	**599**	(211)
Net earnings (loss) from continuing operations	**318**	(46)	**782**	(235)
Net earnings (loss) from discontinued operations (note 4)	**162**	(5)	**414**	(5)
Net Earnings (Loss)	**480**	(51)	**1 196**	(240)
Net Earnings (Loss) From Continuing Operations per Common Share (dollars)				
Basic	**0.20**	(0.05)	**0.50**	(0.25)
Diluted	**0.20**	(0.05)	**0.50**	(0.25)
Net Earnings (Loss) per Common Share (dollars), (note 9)				
Basic	**0.31**	(0.06)	**0.77**	(0.26)
Diluted	**0.31**	(0.06)	**0.76**	(0.26)
Cash dividends	**0.10**	0.05	**0.20**	0.10

Consolidated Statements of Comprehensive Income

(unaudited)

($ millions)	Three months ended June 30 2010	2009	Six months ended June 30 2010	2009
Net earnings (loss)	**480**	(51)	**1 196**	(240)
Other comprehensive income (loss), net of tax				
Change in foreign currency translation adjustment	**(7)**	(96)	**(436)**	(64)
Gain on derivative contracts designated as cash flow hedges	**—**	—	**—**	2
Comprehensive Income (Loss)	**473**	(147)	**760**	(302)

Consolidated Balance Sheets

(unaudited)

($ millions)	**June 30 2010**	December 31 2009
Assets		
Current assets		
Cash and cash equivalents	**455**	505
Accounts receivable	**4 579**	3 703
Inventories	**2 808**	2 947
Income taxes receivable	**650**	587
Future income taxes	**359**	332
Assets of discontinued operations (note 4)	**249**	257
Total current assets	**9 100**	8 331
Property, plant and equipment, net (note 5)	**54 229**	54 198
Other assets	**477**	491
Goodwill	**3 201**	3 201
Future income taxes	**12**	193
Assets of discontinued operations (note 4)	**2 243**	3 332
Total assets	**69 262**	69 746
Liabilities and Shareholders' Equity		
Current liabilities		
Short-term debt	**2**	2
Current portion of long-term debt (note 13)	**21**	25
Accounts payable and accrued liabilities	**5 989**	6 307
Income taxes payable	**1 484**	1 254
Future income taxes	**19**	18
Liabilities of discontinued operations (note 4)	**162**	242
Total current liabilities	**7 677**	7 848
Long-term debt (note 13)	**13 609**	13 855
Accrued liabilities and other	**3 989**	4 372
Future income taxes	**8 606**	8 367
Liabilities of discontinued operations (note 4)	**758**	1 193
Shareholders' equity	**34 623**	34 111
Total liabilities and shareholders' equity	**69 262**	69 746

Shareholders' Equity

	Number (thousands)		Number (thousands)	
Share capital	**1 562 168**	**20 102**	1 559 778	20 053
Contributed surplus		**541**		526
Accumulated other comprehensive income (loss) (note 15)		**(669)**		(233)
Retained earnings		**14 649**		13 765
Total shareholders' equity		**34 623**		34 111

Consolidated Statements of Cash Flows

(unaudited)

($ millions)	Three months ended June 30 2010	2009	Six months ended June 30 2010	2009
Operating Activities				
Net earnings (loss) from continuing operations	**318**	(46)	**782**	(235)
Adjustments for:				
Depreciation, depletion and amortization	**1 050**	296	**1 869**	580
Future income taxes	**76**	(273)	**169**	(415)
Accretion of asset retirement obligations	**45**	28	**88**	56
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt (note 7)	**376**	(405)	**116**	(257)
Change in fair value of derivative contracts (note 6)	**(173)**	715	**(253)**	1 372
Loss (gain) on disposal of assets	**(4)**	5	**(28)**	22
Stock-based compensation	**(3)**	48	**(80)**	103
Other	**(104)**	(113)	**(148)**	(188)
Exploration expenses	**18**	31	**34**	31
Decrease (increase) in non-cash working capital related to operating activities (note 10)	**63**	(139)	**(772)**	(657)
Cash flow provided by continuing operations	**1 662**	147	**1 777**	412
Cash flow provided by discontinued operations	**170**	5	**321**	17
Cash flow from operating activities	**1 832**	152	**2 098**	429
Investing Activities				
Capital and exploration expenditures	**(1 476)**	(623)	**(2 523)**	(1 701)
Other investments	**(4)**	(14)	**(3)**	(31)
Proceeds from disposals	**64**	27	**122**	27
Increase in non-cash working capital related to investing activities	**(147)**	(285)	**(141)**	(678)
Cash flow used in continuing investing activities	**(1 563)**	(895)	**(2 545)**	(2 383)
Cash flow provided by (used in) discontinued investing activities	**216**	(13)	**1 019**	(41)
Cash flow used in investing activities	**(1 347)**	(908)	**(1 526)**	(2 424)
Net cash surplus (deficiency) before financing activities	**485**	(756)	**572**	(1 995)
Financing Activities				
Increase in short-term debt	**—**	—	**—**	1
Net increase (decrease) in revolving-term debt	**(505)**	861	**(354)**	1 898
Issuance of common shares under stock option plan	**20**	7	**35**	22
Dividends paid on common shares	**(154)**	(47)	**(307)**	(94)
Cash flow provided by financing activities	**(639)**	821	**(626)**	1 827
Increase (Decrease) in Cash and Cash Equivalents	**(154)**	65	**(54)**	(168)
Effect of Foreign Exchange on Cash and Cash Equivalents	**7**	(11)	**4**	(7)
Cash and Cash Equivalents at Beginning of Period	**602**	431	**505**	660
Cash and Cash Equivalents at End of Period	**455**	485	**455**	485

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 loss	—	—	—	(240)
Dividends paid on common shares	—	—	—	(94)
Issued for cash under stock option plan	27	(5)	—	—
Stock-based compensation expense	—	51	—	—
Income tax benefit of stock option deduction in the U.S.	—	4	—	—
Change in accumulated other comprehensive income (loss)	—	—	(62)	—
At June 30, 2009	1 140	338	35	12 691
At December 31, 2009	20 053	526	(233)	13 765
Net earnings	**—**	**—**	**—**	**1 196**
Dividends paid on common shares	**—**	**—**	**—**	**(307)**
Issued for cash under stock option plans	**44**	**(9)**	**—**	**—**
Issued under dividend reinvestment plan	**5**	**—**	**—**	**(5)**
Stock-based compensation expense	**—**	**24**	**—**	**—**
Change in accumulated other comprehensive income (loss)	**—**	**—**	**(436)**	**—**
At June 30, 2010	**20 102**	**541**	**(669)**	**14 649**

Schedule of Segmented Data from Continuing Operations

(unaudited)

Three months ended June 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
EARNINGS												
Revenues												
Operating revenues	**1 916**	826	**198**	41	**1 146**	—	**5 129**	1 842	**(49)**	43	**8 340**	2 752
Less: Royalties	**(182)**	(138)	**(3)**	13	**(314)**	—	**—**	—	**—**	—	**(499)**	(125)
Operating revenues (net of royalties)	**1 734**	688	**195**	54	**832**	—	**5 129**	1 842	**(49)**	43	**7 841**	2 627
Energy supply and trading activities	**—**	—	**—**	—	**—**	—	**—**	—	**1 103**	2 120	**1 103**	2 120
Intersegment revenues	**814**	369	**—**	7	**163**	—	**65**	—	**(1 042)**	(376)	**—**	—
Interest and other income	**24**	—	**—**	—	**1**	—	**39**	—	**(3)**	1	**61**	1
	2 572	1 057	**195**	61	**996**	—	**5 233**	1 842	**9**	1 788	**9 005**	4 748
Expenses												
Purchases of crude oil and products	**311**	164	**—**	—	**109**	—	**4 340**	1 448	**(1 033)**	(319)	**3 727**	1 293
Operating, selling and general	**997**	1 058	**83**	32	**111**	—	**545**	168	**103**	71	**1 839**	1 329
Energy supply and trading activities	**—**	—	**—**	—	**—**	—	**—**	—	**989**	2 165	**989**	2 165
Transportation	**77**	59	**23**	4	**25**	—	**48**	5	**(10)**	(5)	**163**	63
Depreciation, depletion and amortization	**454**	197	**185**	39	**273**	—	**114**	54	**24**	6	**1 050**	296
Accretion of asset retirement obligations	**30**	25	**7**	2	**7**	—	**1**	1	**—**	—	**45**	28
Exploration	**—**	—	**—**	32	**47**	—	**—**	—	**—**	—	**47**	32
Loss (gain) on disposal of assets	**2**	—	**(1)**	(15)	**—**	—	**(6)**	20	**1**	—	**(4)**	5
Project start-up costs	**14**	10	**—**	—	**1**	—	**—**	—	**—**	—	**15**	10
Financing expenses (income)	**—**	—	**(4)**	—	**(26)**	—	**(5)**	—	**513**	(268)	**478**	(268)
	1 885	1 513	**293**	94	**547**	—	**5 037**	1 696	**587**	1 650	**8 349**	4 953
Earnings (loss) before income taxes	**687**	(456)	**(98)**	(33)	**449**	—	**196**	146	**(578)**	138	**656**	(205)
Income taxes	**(170)**	149	**30**	10	**(232)**	—	**(58)**	(47)	**92**	47	**(338)**	159
Net earning (loss) from continuing operations	**517**	(307)	**(68)**	(23)	**217**	—	**138**	99	**(486)**	185	**318**	(46)
CAPITAL AND EXPLORATION EXPENDITURES – continuing operations	**(989)**	(528)	**(31)**	(68)	**(202)**	—	**(177)**	(26)	**(77)**	(1)	**(1 476)**	(623)

Schedule of Segmented Data from Continuing Operations (continued)

(unaudited)

Six months ended June 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
EARNINGS												
Revenues												
Operating revenues	**2 850**	1 763	**438**	104	**2 220**	—	**9 852**	3 256	**42**	89	**15 402**	5 212
Less: Royalties	**(252)**	(146)	**(39)**	—	**(650)**	—	**—**	—	**—**	—	**(941)**	(146)
Operating revenues (net of royalties)	**2 598**	1 617	**399**	104	**1 570**	—	**9 852**	3 256	**42**	89	**14 461**	5 066
Energy supply and trading activities	**—**	—	**—**	—	**—**	—	**—**	—	**1 447**	4 288	**1 447**	4 288
Intersegment revenues	**1 684**	540	**16**	22	**294**	—	**151**	—	**(2 145)**	(562)	**—**	—
Interest and other income	**190**	—	**—**	—	**—**	—	**39**	—	**(160)**	1	**69**	1
	4 472	2 157	**415**	126	**1 864**	—	**10 042**	3 256	**(816)**	3 816	**15 977**	9 355
Expenses												
Purchases of crude oil and products	**601**	226	**—**	—	**163**	—	**8 275**	2 460	**(2 082)**	(468)	**6 957**	2 218
Operating, selling and general	**2 115**	1 996	**145**	67	**170**	—	**1 052**	345	**163**	112	**3 645**	2 520
Energy supply and trading activities	**—**	—	**—**	—	**—**	—	**—**	—	**1 351**	4 285	**1 351**	4 285
Transportation	**140**	116	**38**	8	**51**	—	**93**	9	**(16)**	(9)	**306**	124
Depreciation, depletion and amortization	**723**	380	**317**	77	**563**	—	**232**	107	**34**	16	**1 869**	580
Accretion of asset retirement obligations	**60**	52	**13**	3	**13**	—	**2**	1	**—**	—	**88**	56
Exploration	**5**	6	**11**	33	**77**	—	**—**	—	**—**	—	**93**	39
Loss (gain) on disposal of assets	**11**	17	**(37)**	(15)	**—**	—	**(3)**	20	**1**	—	**(28)**	22
Project start-up costs	**24**	26	**—**	—	**3**	—	**—**	—	**—**	—	**27**	26
Financing expenses (income)	**—**	—	**(4)**	—	**(32)**	—	**(1)**	—	**325**	(69)	**288**	(69)
	3 679	2 819	**483**	173	**1 008**	—	**9 650**	2 942	**(224)**	3 867	**14 596**	9 801
Earnings (loss) before income taxes	**793**	(662)	**(68)**	(47)	**856**	—	**392**	314	**(592)**	(51)	**1 381**	(446)
Income taxes	**(200)**	245	**23**	14	**(430)**	—	**(115)**	(103)	**123**	55	**(599)**	211
Net earning (loss) from continuing operations	**593**	(417)	**(45)**	(33)	**426**	—	**277**	211	**(469)**	4	**782**	(235)
CAPITAL AND EXPLORATION EXPENDITURES – continuing operations	**(1 680)**	(1 494)	**(70)**	(149)	**(433)**	—	**(243)**	(53)	**(97)**	(5)	**(2 523)**	(1 701)

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 June 30, 2010 and the results of its operations and cash flows for the three and six month periods ended June 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. As at June 30, 2010, a provision of $29 million remains unsettled relating to exiting certain activities of Petro-Canada and involuntary termination benefits.

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 March 1, 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.

On March 31, 2010, the company completed the sale of certain non-core natural gas properties located in northeast British Columbia (Blueberry and Jedney) for net proceeds of $383 million.

On May 31, 2010, the company completed the sale of certain non-core assets in central Alberta (Rosevear and Pine Creek) for net proceeds of $229 million.

On June 23, 2010, the company entered into an agreement to sell certain non-core assets in west central Alberta (Bearberry and Ricinus) for gross proceeds of $285 million before closing adjustments. The sale is expected to close in the third quarter of 2010 and is subject to closing conditions and regulatory approvals typical of transactions of this nature.

International and Offshore

On February 25, 2010, Suncor entered into an agreement to sell its assets in Trinidad and Tobago for gross proceeds of US$380 million before closing adjustments. The sale is now expected to close in the third quarter of 2010 and is subject to customary closing conditions, Trinidad and Tobago government approval and other regulatory approvals.

On June 14, 2010, the company entered into an agreement to sell all of its shares in Petro-Canada Netherlands B.V., for gross proceeds of €445 million before closing adjustments. The sale is expected to close in the third quarter of 2010 and is subject to closing conditions and regulatory approvals typical of transactions of this nature.

Suncor has decided to divest certain non-core North Sea assets in the U.K. and these operations have been accounted for as discontinued operations. Assets that are planned to be divested include Scott/Telford and Triton. The company expects to maintain its ownership positions in the producing Buzzard field, and exploration assets in the Hobby, Golden Eagle and Pink fields. At June 30, 2010, no agreement has been reached on the sale of these non-core North Sea assets.

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

	Three months ended June 30					
	Natural Gas		**International and Offshore**		**Total**	
($ millions)	**2010**	2009	**2010**	2009	**2010**	2009
Revenues						
Operating revenues	**65**	26	**161**	—	**226**	26
Less: Royalties	**(3)**	(6)	**—**	—	**(3)**	(6)
Operating revenues (net of royalties)	**62**	20	**161**	—	**223**	20
Interest and other income	**—**	—	**(3)**	—	**(3)**	—
Gain on disposal of assets	**144**	—	**—**	—	**144**	—
	206	20	**158**	—	**364**	20
Expenses						
Operating, selling and general	**16**	9	**34**	—	**50**	9
Transportation	**8**	2	**6**	—	**14**	2
Depreciation, depletion and amortization	**31**	15	**3**	—	**34**	15
Accretion of asset retirement obligations	**2**	1	**5**	—	**7**	1
Exploration	**—**	—	**3**	—	**3**	—
Financing expenses	**—**	—	**7**	—	**7**	—
	57	27	**58**	—	**115**	27
Earnings before income taxes	**149**	(7)	**100**	—	**249**	(7)
Income taxes	**36**	(2)	**51**	—	**87**	(2)
Net earnings	**113**	(5)	**49**	—	**162**	(5)

	Three months ended June 30	
(dollars)	**2010**	2009
Basic earnings per share from discontinued operations	**0.11**	(0.01)
Diluted earnings per share from discontinued operations	**0.11**	(0.01)

	Natural Gas		International and Offshore		Total	
					Six months ended June 30	
($ millions)	**2010**	2009	**2010**	2009	**2010**	2009
Revenues						
Operating revenues	**224**	62	**372**	—	**596**	62
Less: Royalties	**(33)**	(16)	**—**	—	**(33)**	(16)
Operating revenues (net of royalties)	**191**	46	**372**	—	**563**	46
Interest and other income	**—**	—	**—**	—	**—**	—
Gain on disposal of assets	**375**	—	**—**	—	**375**	—
	566	46	**372**	—	**938**	46
Expenses						
Operating, selling and general	**50**	16	**72**	—	**122**	16
Transportation	**15**	3	**14**	—	**29**	3
Depreciation, depletion and amortization	**68**	33	**59**	—	**127**	33
Accretion of asset retirement obligations	**6**	2	**11**	—	**17**	2
Exploration	**—**	—	**5**	—	**5**	—
Financing expenses	**7**	—	**8**	—	**15**	—
	146	54	**169**	—	**315**	54
Earnings before income taxes	**420**	(8)	**203**	—	**623**	(8)
Income taxes	**109**	(3)	**100**	—	**209**	(3)
Net earnings	**311**	(5)	**103**	—	**414**	(5)

	Six months ended June 30	
(dollars)	**2010**	2009
Basic earnings per share from discontinued operations	**0.27**	(0.01)
Diluted earnings per share from discontinued operations	**0.26**	(0.01)

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

	Natural Gas		International and Offshore		Total	
	June 30	December 31	**June 30**	December 31	**June 30**	December 31
($ millions)	**2010**	2009	**2010**	2009	**2010**	2009
Assets						
Current assets	**17**	34	**232**	223	**249**	257
Property, plant and equipment, net	**622**	1 600	**1 621**	1 732	**2 243**	3 332
Total assets	**639**	1 634	**1 853**	1 955	**2 492**	3 589
Liabilities						
Current liabilities	**17**	64	**145**	178	**162**	242
Accrued liabilities and other	**152**	286	**373**	404	**525**	690
Future income taxes	**—**	31	**233**	472	**233**	503
Total liabilities	**169**	381	**751**	1 054	**920**	1 435

5. ASSET WRITEDOWN

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. These assets were being used in the development of an alternative extraction process to crush and slurry oil sands at the mine face, which the company has discontinued.

During the second quarter of 2010, the company recognized a charge of $44 million to reflect the write-down of certain land leases in the Natural Gas operating segment. These assets are in areas of Western Canada and Alaska that the company does not plan to pursue given its strategic business alignment.

These charges are included in depreciation, depletion and amortization expenses 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 June 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 June 30, 2010, the carrying value of our fixed-term debt accounted for under the amortized cost method was $10.3 billion (December 31, 2009 – $10.1 billion) and the fair value was $11.4 billion (December 31, 2009 – $10.7 billion).

(b) Hedge Accounting

For a detailed discussion of fair value and cash flow hedges, see page 75 of Suncor's 2009 Annual Report.

Fair Value Hedges

At June 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 $13 million at June 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 six month periods ended June 30, 2010 and June 30, 2009.

Cash Flow Hedges

At June 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 adverse 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 June 30, 2010, was a gain of $76 million, net of income taxes of $25 million (2009 – a loss of $542 million, net of income taxes of $199 million). During the six month period ended June 30, 2010, the earnings impact was a gain of $81 million, net of income taxes of $27 million (2009 – loss of $690 million, net of income taxes of $258 million).

Significant contracts outstanding at June 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 June 30, 2010, was a gain of $32 million, net of income taxes of $13 million (2009 – a loss of $62 million, net of income taxes of $24 million). During the six month period ended June 30, 2010, the earnings impact was a gain of $50 million, net of income taxes of $20 million (2009 – loss of $14 million, net of income taxes of $6 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	**103**	**(28)**	**75**
Changes in fair value attributable to market price and other market changes during the period	**108**	**70**	**178**
Fair value of contracts outstanding at June 30, 2010 [(a), (b)]	**(101)**	**(5)**	**(106)**

(a) As at June 30, 2010, of the total unrealized derivatives, $132 million is recorded in accounts receivable (December 31, 2009 – $213 million recorded in accounts receivable) in the Consolidated Balance Sheets.

(b) As at June 30, 2010, of the total unrealized derivatives, $238 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 June 30, 2010, the company's exposure to risks arising from the use of financial instruments had not changed significantly from December 31, 2009.

For a full discussion of the company's financial risk factors, see page 78 of Suncor's 2009 Annual Report.

7. FINANCING EXPENSES (INCOME)

	Three months ended June 30		Six months ended June 30	
($ millions)	**2010**	2009	**2010**	2009
Interest on debt	**167**	117	**351**	235
Capitalized interest	**(62)**	(18)	**(138)**	(72)
Interest expense	**105**	99	**213**	163
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**376**	(405)	**116**	(257)
Other foreign exchange (gain) loss	**(3)**	38	**(41)**	25
Total financing expenses (income) from continuing operations [(1)]	**478**	(268)	**288**	(69)

(1) For the three months ended June 30, 2010 $7 million (2009 – nil) has been reclassified to net earnings from discontinued operations. For the six months ended June 30, 2010 $15 million (2009 – nil) has been reclassified to net earnings from discontinued operations.

8. INCOME TAXES

($ millions)	Three months ended June 30 2010	2009	Six months ended June 30 2010	2009
Provision for (recovery of) income taxes:				
Current:				
Canada	**13**	112	**16**	192
Foreign	**249**	2	**414**	12
Future:				
Canada	**125**	(298)	**209**	(455)
Foreign	**(49)**	25	**(40)**	40
Total provision (recovery) for income taxes from continuing operations[(1)]	**338**	(159)	**599**	(211)

(1) For the three months ended June 30, 2010 $87 million (2009 – $(2)) has been reclassified to net earnings from discontinued operations. For the six months ended June 30, 2010 $209 million (2009 – $(3)) has been reclassified to net earnings from discontinued operations.

9. RECONCILIATION OF BASIC AND DILUTED EARNINGS (LOSS) PER COMMON SHARE

($ millions)	Three months ended June 30 2010	2009	Six months ended June 30 2010	2009
Net earnings (loss)	**480**	(51)	**1 196**	(240)
(millions of common shares)				
Weighted-average number of common shares	**1 562**	937	**1 561**	937
Dilutive securities:				
Options issued under stock-based compensation plans	**11**	10	**12**	9
Weighted-average number of diluted common shares	**1 573**	947	**1 573**	946
(dollars per common share)				
Basic earnings per share[(a)]	**0.31**	(0.06)	**0.77**	(0.26)
Diluted earnings per share[(b)]	**0.31**	(0.06)	**0.76**	(0.26)

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:

($ millions)	Three months ended June 30 2010	2009	Six months ended June 30 2010	2009
Operating activities				
Accounts receivable	**169**	(225)	**(746)**	(366)
Inventories	**177**	(154)	**117**	(381)
Accounts payable and accrued liabilities	**(459)**	304	**(310)**	331
Taxes payable/receivable	**176**	(64)	**167**	(241)
	63	(139)	**(772)**	(657)

11. EMPLOYEE FUTURE BENEFITS LIABILITY

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

	Pension Benefits			
	Three months ended June 30		Six months ended June 30	
($ millions)	**2010**	2009	**2010**	2009
Current service costs	**21**	13	**43**	26
Interest costs	**42**	13	**84**	26
Expected return on plan assets	**(35)**	(10)	**(71)**	(20)
Amortization of net actuarial loss	**2**	5	**4**	10
Net periodic benefit cost	**30**	21	**60**	42

	Other Post-Retirement Benefits			
	Three months ended June 30		Six months ended June 30	
($ millions)	**2010**	2009	**2010**	2009
Current service costs	**2**	2	**4**	3
Interest costs	**6**	3	**12**	5
Net periodic benefit cost	**8**	5	**16**	8

12. SHARE CAPITAL

Issued

	Number (thousands)	Common Shares Amount ($ millions)
Balance as at December 31, 2009	1 559 778	20 053
Issued for cash under stock option plans	**2 238**	**44**
Issued under dividend reinvestment plan	**152**	**5**
Balance as at June 30, 2010	**1 562 168**	**20 102**

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 are terminated or otherwise result in no underlying common share being issued will be available for issuance as options under this plan. The company granted 21,000 options with tandem stock appreciation rights under this plan during the second quarter of 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	**4 256**	**31.85**
Exercised	**(2 230)**	**14.19**
Forfeited/expired	**(1 849)**	**41.16**
Outstanding, June 30, 2010	**72 201**	**32.56**

(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 did not grant any SARs under this new plan during the second 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	**346**	**31.85**
Exercised	**(337)**	**21.54**
Forfeited/expired	**(1 199)**	**28.84**
Outstanding, June 30, 2010	**12 875**	**28.89**

(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	**1 655**	**2 796**	**27**
Redeemed	**(271)**	**(11)**	**(137)**
Forfeited	**(753)**	**(231)**	**—**
Reinvested	**13**	**22**	**15**
Outstanding, June 30, 2010	**3 891**	**6 826**	**2 521**

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 June 30		Six months ended June 30	
($ millions)	**2010**	2009	**2010**	2009
Stock option plans	**7**	24	**(15)**	51
SARs	**(4)**	—	**(22)**	—
PSUs	**6**	2	**(7)**	10
RSUs	**12**	12	**35**	25
DSUs	**(5)**	14	**(15)**	23
Total stock based compensation expense (recovery)	**16**	52	**(24)**	109

13. LONG-TERM DEBT AND CREDIT FACILITIES

($ millions)	June 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)	**795**	785
6.80% Notes, denominated in U.S. dollars, due in 2038 (US$900)	**984**	972
6.50% Notes, denominated in U.S. dollars, due in 2038 (US$1150)	**1 220**	1 204
5.95% Notes, denominated in U.S. dollars, due in 2035 (US$600)	**587**	578
5.95% Notes, denominated in U.S. dollars, due in 2034 (US$500)	**530**	523
5.35% Notes, denominated in U.S. dollars, due in 2033 (US$300)	**271**	266
7.15% Notes, denominated in U.S. dollars, due in 2032 (US$500)	**530**	523
6.10% Notes, denominated in U.S. dollars, due in 2018 (US$1250)	**1 326**	1 308
6.05% Notes, denominated in U.S. dollars, due in 2018 (US$600)	**651**	643
5.00% Notes, denominated in U.S. dollars, due in 2014 (US$400)	**433**	429
4.00% Notes, denominated in U.S. dollars, due in 2013 (US$300)	**317**	313
7.00% Debentures, denominated in U.S. dollars, due in 2028 (US$250)	**275**	271
7.875% Debentures, denominated in U.S. dollars, due in 2026 (US$275)	**329**	325
9.25% Debentures, denominated in U.S. dollars, due in 2021 (US$300)	**404**	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
	10 452	10 342
Revolving-term debt, with interest at variable rates		
Commercial paper, bankers' acceptances and LIBOR loans	**2 890**	3 244
Total unsecured long-term debt	**13 342**	13 586
Secured long-term debt	**13**	13
Capital leases	**323**	326
Debt fair value adjustment for interest swaps	**13**	18
Deferred financing costs	**(61)**	(63)
	13 630	13 880
Current portion of long-term debt		
Capital leases	**(10)**	(14)
Fair value of interest swaps	**(11)**	(11)
Total current portion of long-term debt	**(21)**	(25)
Total long-term debt	**13 609**	13 855

At June 30, 2010, undrawn lines of credit were $4,423 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	**209**
Facilities that are fully revolving for a period of five years and expires in 2013	**7 320**
Facilities that can be terminated at any time at the option of the lenders	**458**
Total available credit facilities	**7 991**
Credit facilities supporting outstanding commercial paper, bankers' acceptances and LIBOR loans	**(2 890)**
Credit facilities supporting letters of credit	**(678)**
Total undrawn credit facilities	**4 423**

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 monitors capital through two key ratios: 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 June 30, 2010 and December 31, 2009.

During the second 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 June 30, ($ millions)	Capital Measure Target	2010	2009
Components of ratios			
Short-term debt		**2**	3
Current portion of long-term debt		**21**	20
Long-term debt		**13 609**	9 508
Total debt		**13 632**	9 531
Cash and equivalents		**455**	485
Net debt		**13 177**	9 046
Shareholders' equity		**34 623**	14 204
Total capitalization (total debt + shareholders' equity)		**48 255**	23 735
Cash flow from operations(1) (trailing twelve months)		**4 585**	2 473
Net debt/cash flow from operations	<2.0 times	**2.9**	3.7
Total debt/total debt plus shareholders' equity		**28%**	40%

(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)	**June 30 2010**	December 31 2009
Unrealized foreign currency translation adjustment	**(684)**	(248)
Unrealized gains on derivative hedging activities	**15**	15
Total	**(669)**	(233)

16. SUPPLEMENTAL INFORMATION

	Three months ended June 30		Six months ended June 30	
($ millions)	**2010**	2009	**2010**	2009
Interest paid	**258**	173	**347**	234
Income taxes paid	**40**	155	**271**	395

SUNCOR
ENERGY

Box 38, 112 – 4th Avenue S.W., Calgary, Alberta, Canada T2P 2V5
tel: (403) 269-8100 fax: (403) 269-6217 info@suncor.com www.suncor.com