SECOND QUARTER 2009
Report to shareholders for the period ended June 30, 2009

Suncor Energy second quarter results

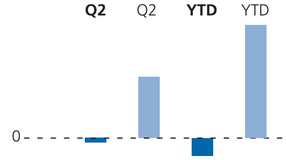
All financial figures are unaudited and in Canadian dollars unless noted otherwise. Certain financial measures referred to in this document are not prescribed by Canadian generally accepted accounting principles (GAAP). For a description of these measures, see Non-GAAP Financial Measures in Suncor's 2009 second quarter Management's Discussion and Analysis. This document makes reference to barrels of oil equivalent (boe). A boe conversion ratio of six thousand cubic feet of natural gas: one barrel of crude oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Accordingly, boe measures may be misleading, particularly if used in isolation.

Suncor Energy Inc. recorded a second quarter 2009 net loss of $51 million ($0.06 per common share), compared to net earnings of $829 million ($0.89 per common share) in the second quarter of 2008. Excluding unrealized foreign exchange gain on the company's U.S. dollar denominated long-term debt, mark-to-market accounting losses on commodity derivatives, and costs related to start-up or deferral of growth projects, second quarter 2009 earnings were $185 million ($0.20 per common share), compared to $920 million ($0.99 per common share) in the second quarter of 2008. Cash flow used in operations was $342 million in the second quarter of 2009, compared to cash flow from operations of $1.405 billion in the second quarter of 2008.

The decrease in earnings and cash flow was primarily due to lower price realizations, as benchmark commodity prices were significantly weaker in the second quarter of 2009 compared to the same period in 2008, and operating expenses were higher at oil sands due to increased production and sales. These were partially offset by the increased production in our oil sands business segment, reduced natural gas royalty expense due to lower benchmark commodity prices, and increased refined product sales in our downstream business segment.

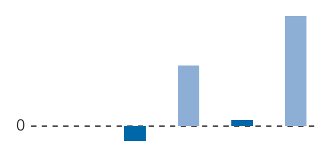
Net loss for the first six months of 2009 was $240 million, compared to net earnings of $1.537 billion for the same period in 2008. Excluding unrealized foreign exchange impacts on the company's U.S. dollar denominated long-term debt, mark-to-market accounting losses on commodity derivatives, and costs related to start-up or deferral of growth projects, earnings for the first six months of 2009 were $410 million, compared to $1.725 billion in the same period for 2008. Cash flow from operations for the first six months of 2009 was $137 million, compared to $2.566 billion in the first six months of 2008. The year-to-date decreases in earnings and cash flow from operations were primarily due to the same factors that impacted second quarter results.

Net Earnings by Quarter
($ millions)



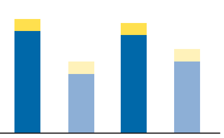
	2009 Q2	2008 Q2	2009 YTD	2008 YTD
	(51)	829	**(240)**	1,537

Cash Flow from Operations by Quarter
($ millions)



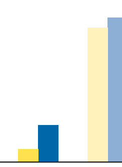
	2009 Q2	2008 Q2	2009 YTD	2008 YTD
	(342)	1,405	**137**	2,566

Production
(thousands of barrels of oil equivalent per day)



	2009 Q2	2008 Q2	2009 YTD	2008 YTD
Natural Gas	**35.1**	37.7	**35.8**	37.9
Oil Sands	**301.0**	174.6	**289.0**	211.0
Total	**336.1**	212.3	**324.8**	248.9

Ratios
(percent)
for the twelve months ended June 30



	2009	2008
Return on average shareholders' equity	**2.6**	26.8
Return on capital employed	**7.3**	28.8

Suncor's total upstream production averaged 336,100 barrels of oil equivalent (boe) per day during the second quarter of 2009, compared to 212,300 boe per day in the second quarter of 2008. Oil sands production contributed an average 301,000 barrels per day (bpd) in the second quarter of 2009, compared to second quarter 2008 production of 174,600 bpd. The increased production was primarily due to improved upgrader reliability in the second quarter of 2009. In addition, in the comparative quarter of 2008 a planned maintenance shutdown of one of our upgraders and a regulatory cap on our Firebag in-situ operations impacted production. Natural gas production this most recent quarter averaged 211 million cubic feet equivalent (mmcfe) per day, compared to 226 mmcfe per day in the second quarter of 2008.

Oil sands cash operating costs averaged $31.30 per barrel in the second quarter of 2009, compared to $50.85 per barrel during the second quarter of 2008. The decrease in cash operating costs per barrel was primarily due to increased production and a decrease in natural gas input prices.

"During the second quarter, we saw the fruits of last year's labour," said Rick George, president and chief executive officer. "For the second quarter in a row, we experienced very good reliability at oil sands, which is clearly illustrated through our production results during the first half of 2009. As we look to the second half of the year, we are confident that we are well-positioned to take advantage of any improvement in commodity prices with more reliable operations."

Merger and growth update

On March 23, 2009, Suncor and Petro-Canada (TSX:PCA) (NYSE:PCZ) announced that they have agreed to merge the two companies. The merger has received shareholder, court and Competition Bureau approval and with all the conditions necessary to complete the transaction satisfied, Suncor and Petro-Canada intend to make the merger effective August 1, 2009. The combined entity will operate corporately and trade under the Suncor name while maintaining the strong brand presence and customer loyalty of Petro-Canada in refined products.

During the second quarter of 2009, work continued on the Firebag sulphur plant and the Steepbank extraction plant. The sulphur plant is expected to support sulphur emissions reductions for existing and planned in-situ development, and the extraction plant is expected to provide improved reliability and productivity for the company's oil sands assets. The project cost for the Steepbank extraction plant is expected to exceed the previous cost estimate ($850 million +/−10%) with a final estimated cost of $980 million (+5%) as a result of labour shortages and the resulting productivity challenges, as well as premiums incurred to maintain the project schedule. Both of these projects are scheduled for completion in the third quarter of 2009. For an update on our significant capital projects currently in progress see page 11.

As previously announced, we deferred the company's growth projects in our revised 2009 capital budget. We do not anticipate any changes to our growth project plans until after the close of the proposed merger with Petro-Canada. At that time, all capital projects from both predecessor companies will be reviewed with capital investment directed toward projects with the strongest near-term cash flow potential, highest anticipated return on capital and lowest risk.

Outlook

Suncor's outlook provides management's targets for 2009 in certain key areas of the company's business. Outlook forecasts are subject to change.

	Six Month Actuals Ended June 30, 2009	2009 Full Year Outlook
Oil Sands		
Production (bpd)(1)	**289 000**	300 000 (+5%/−10%)
Sales		
Diesel	**9%**	10%
Sweet	**39%**	38%
Sour	**48%**	49%
Bitumen	**4%**	3%
Realization on crude sales basket(2)	**WTI @ Cushing less Cdn$4.99 per barrel**	WTI @ Cushing less Cdn$4.50 to Cdn$5.50 per barrel
Cash operating costs(3)	**$32.50 per barrel**	$33.00 to $38.00 per barrel
Natural Gas		
Production(4) (mmcf equivalent per day)	**215**	210 (+5%/−5%)
Natural gas	**91%**	92%
Liquids	**9%**	8%

(1) Includes 22,000 bpd in the first six months of 2009 processed by Suncor for Petro-Canada for which Suncor receives a processing fee. Volumes received under this arrangement are not included as purchases for financial statement presentation.

(2) Excludes the impact of hedging activities.

(3) Cash operating cost estimates are based on the following assumptions: (i) production volumes and sales mix as described in the table above; and (ii) a natural gas price of $4.50 per gigajoule ($4.75 per mcf) at AECO. This goal also includes costs incurred for third-party bitumen processing but does not include costs related to deferral of growth projects. Based on second quarter results and expectations for the balance of the year, the natural gas price assumption has been reduced from the previous $7.10 per gigajoule at AECO. This change in assumption had no material impact on our cash operating costs per barrel outlook for 2009. Cash operating costs per barrel is not prescribed by Canadian generally accepted accounting principles (GAAP). This non-GAAP financial measure does not have any standardized meaning and therefore is unlikely to be comparable to similar measures presented by other companies. Suncor includes this non-GAAP financial measure because investors may use this information to analyze operating performance. This information should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP. See Non-GAAP Financial Measures on page 15.

(4) Production target includes natural gas liquids (NGL) and crude oil converted into mmcf equivalent at a ratio of one barrel of NGL/crude oil: six thousand cubic feet of natural gas. This conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. This mmcf equivalent may be misleading, particularly if used in isolation.

The 2009 outlook is based on Suncor's current estimates, projections and assumptions for the 2009 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 of the 2009 outlook include implementing reliability and operational efficiency initiatives that are expected to minimize unplanned maintenance in 2009.

Factors that could potentially impact Suncor's operations and financial performance in 2009 include:

- Bitumen supply. Ore grade quality, unplanned mine equipment and extraction plant maintenance, tailings storage and in-situ reservoir performance could impact 2009 production targets. Production could also be impacted by the availability of third-party bitumen.
- Performance of recently commissioned upgrading facilities. Production rates while new equipment is being lined out are difficult to predict and can be impacted by unplanned maintenance.
- Unplanned maintenance. Production estimates could be impacted if unplanned work is required at any of our mining, production, upgrading, refining or pipeline assets.
- Crude oil hedges. Suncor has hedging agreements for approximately 60% of targeted production in 2009 and for 50,000 bpd in 2010. See Commodity and Treasury Hedging Activities on page 12.

For additional information on risk factors that could cause actual results to differ, please see page 19 of Suncor's 2008 annual report.

Management's Discussion and Analysis

July 21, 2009

This Management's Discussion and Analysis (MD&A) contains forward-looking information based on certain expectations, estimates, projections and assumptions. This information is subject to a number of risks and uncertainties, many of which are beyond the company's control. Users of this information are cautioned that actual results may differ materially. For information on material risk factors and assumptions underlying our forward-looking information, see page 17.

This MD&A should be read in conjunction with our June 30, 2009 unaudited interim consolidated financial statements and notes. Readers should also refer to our MD&A on pages 6 to 42 of our 2008 Annual Report and to our Annual Information Form (AIF) dated March 2, 2009. All financial information is reported in Canadian dollars (Cdn$) and in accordance with Canadian generally accepted accounting principles (GAAP) unless noted otherwise. The financial measures: cash flow from operations, return on capital employed (ROCE) and cash and total operating costs per barrel referred to in this MD&A are not prescribed by GAAP and are outlined and reconciled in Non-GAAP Financial Measures on page 40 of our 2008 Annual Report, and page 15 of this MD&A.

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

Barrels of oil equivalent (boe) may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet (mcf) of natural gas: one barrel of crude oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

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.

The tables and charts in this document form an integral part of this MD&A.

Additional information about Suncor filed with Canadian securities commissions and the United States Securities and Exchange Commission (SEC), including periodic quarterly and annual reports and the AIF 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.

The information in this MD&A does not assume the completion of the proposed merger between Suncor and Petro-Canada, and forward-looking information is presented for Suncor on a stand-alone basis.

Selected Financial Information

Industry Indicators (average for the period)	Three months ended June 30		Six months ended June 30	
	2009	2008	**2009**	2008
West Texas Intermediate (WTI) crude oil US$/barrel at Cushing	**59.60**	124.00	**51.35**	110.95
Canadian 0.3% par crude oil Cdn$/barrel at Edmonton	**65.30**	126.40	**57.70**	112.30
Light/heavy crude oil differential US$/barrel WTI at Cushing less Western Canadian Select at Hardisty	**7.50**	21.65	**8.20**	21.55
Natural Gas US$/mcf at Henry Hub	**3.60**	10.80	**4.15**	9.45
Natural Gas (Alberta spot) Cdn$/mcf at AECO	**3.65**	9.35	**4.65**	8.25
New York Harbour 3-2-1 crack [1] US$/barrel	**8.35**	11.50	**9.10**	10.15
Exchange rate: US$/Cdn$	**0.85**	0.99	**0.83**	0.99

(1) New York Harbour 3-2-1 crack is an industry indicator measuring the margin on a barrel of oil for gasoline and distillate. It is calculated by taking two times the New York Harbour gasoline margin plus one times the New York Harbour distillate margin and dividing by three.

Outstanding Share Data (at June 30, 2009)	
Common shares	937 130 633
Common share options – total	46 127 204
Common share options – exercisable	25 791 569

Summary of Quarterly Results

	2009		2008				2007	
	Three months ended		Three months ended				Three months ended	
($ millions, except per share)	**June 30**	Mar 31	Dec 31	Sept 30	June 30	Mar 31	Dec 31	Sept 30
Revenues	**5 058**	4 814	7 196	8 946	7 959	5 988	5 185	4 802
Net earnings (loss)	**(51)**	(189)	(215)	815	829	708	1 042	627
Net earnings (loss) per common share								
Basic	**(0.06)**	(0.20)	(0.24)	0.87	0.89	0.77	1.12	0.68
Diluted	**(0.06)**	(0.20)	(0.24)	0.86	0.87	0.75	1.10	0.66

Analysis of Consolidated Statements of Earnings and Cash Flows

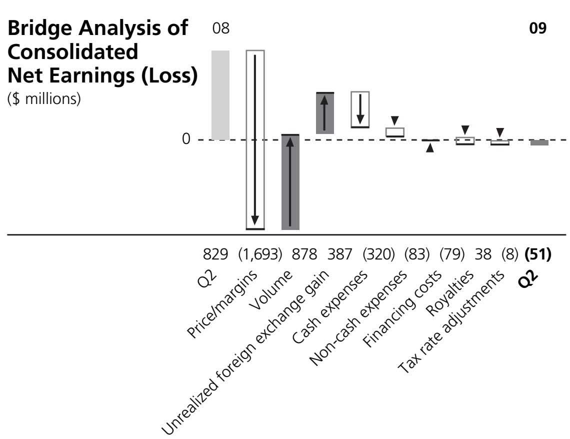
Net loss for the second quarter of 2009 was $51 million, compared to net earnings of $829 million for the second quarter of 2008. Excluding unrealized foreign exchange gain on the company's U.S. dollar denominated long-term debt, mark-to-market accounting losses on commodity derivatives, and costs related to start-up or deferral of growth projects, second quarter 2009 earnings were $185 million ($0.20 per common share), compared to $920 million ($0.99 per common share) in the second quarter of 2008.

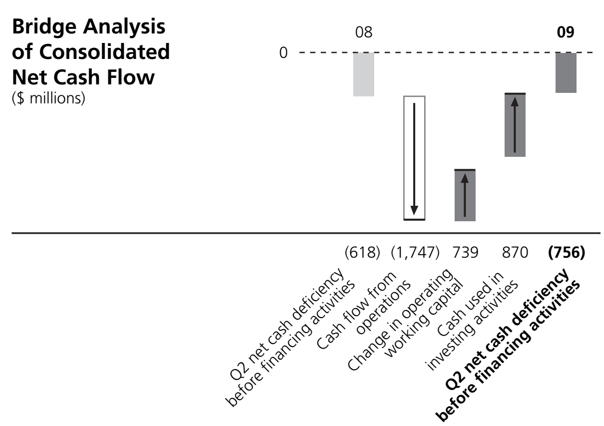
The decrease in earnings was primarily due to lower price realizations, as benchmark commodity prices were significantly weaker in the second quarter of 2009 compared to the same period in 2008, as well as higher operating expenses at oil sands associated with higher production. This was partially offset by increased production in our oil sands business segment, reduced natural gas royalty expense due to lower benchmark commodity prices, and increased refined product sales in our downstream business segment.

Cash flow used in operations in the second quarter of 2009 was $342 million, compared to cash flow from operations of $1.405 billion in the same period of 2008. The decrease was due primarily to the same factors that impacted earnings.

Net loss for the first six months of 2009 was $240 million, compared to net earnings of $1.537 billion for the same period in 2008. Excluding unrealized foreign exchange impacts on the company's U.S. dollar denominated long-term debt, mark-to-market accounting losses on commodity derivatives, and costs related to start-up or deferral of growth projects, earnings for the first six months of 2009 were $410 million, compared to $1.725 billion in the same period for 2008. Cash flow from operations for the first six months of 2009 was $137 million, compared to $2.566 billion in the first six months of 2008. The year-to-date decreases in earnings and cash flow from operations were primarily due to the same factors that impacted second quarter results.

Our effective tax rate for the first half of 2009 was 47%, compared to 30% in the first half of 2008. The higher effective tax rate in the first half of 2009 is primarily a result of foreign exchange adjustments and tax filing reconciliations. During the first six months of 2009, we recorded $204 million in current income tax expense compared to $214 million in the first six months of 2008 (see page 10 for a more detailed discussion).





Net Earnings Components

This table explains some of the factors impacting net earnings on an after-tax basis. For comparability purposes, readers should rely on the reported net earnings presented in our unaudited interim consolidated financial statements and notes in accordance with Canadian GAAP.

	Three months ended June 30		Six months ended June 30	
($ millions, after-tax)	**2009**	2008	**2009**	2008
Earnings before the following items:	**185**	920	**410**	1 725
Mark-to-market accounting loss on commodity derivatives	**(606)**	(99)	**(738)**	(116)
Costs related to deferral of growth projects	**(28)**	—	**(151)**	—
Unrealized foreign exchange gain (loss) on U.S. dollar denominated long-term debt	**405**	18	**257**	(57)
Project start-up costs	**(7)**	(10)	**(18)**	(15)
Net earnings as reported	**(51)**	829	**(240)**	1 537

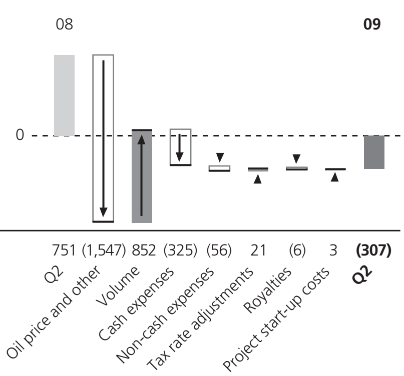
Analysis of Segmented Earnings and Cash Flows

Oil Sands

Oil sands recorded a net loss of $307 million in the second quarter of 2009, compared with net earnings of $751 million in the second quarter of 2008. Excluding the impact of mark-to-market accounting losses on commodity derivatives, and costs related to start-up or deferral of growth projects, earnings for the second quarter of 2009 were $334 million, compared to $860 million in the second quarter of 2008. Earnings decreased primarily as a result of lower average price realizations for oil sands crude products, partially offset by higher production.

The decrease in price realizations reflects significantly lower benchmark West Texas Intermediate (WTI) crude oil prices and a discount to WTI for our sweet crude blends, partially offset by the weaker Canadian dollar and a smaller discount to WTI for our sour crude blends.

Bridge Analysis of Oil Sands Net Earnings
($ millions)



Purchases of crude oil and products were $164 million in the second quarter of 2009, compared to $114 million in the second quarter of 2008. The increase was primarily a result of purchases to optimize bitumen blending and sales. This increase was partially offset by the absence of any planned shutdowns, as the comparative quarter of 2008 saw higher purchases of diesel to meet customer commitments.

Operating expenses were $1.028 billion in the second quarter of 2009, compared to $640 million in the second quarter of 2008. The increase was due primarily to costs associated with higher production and sales. In addition, we incurred costs related to the planned implementation of reliability and operational efficiency initiatives, increased employee costs resulting from a larger number of employees and higher overall salaries, as well as further safe mode costs. These factors were partially offset by lower energy input costs.

We continued to incur costs related to placing certain growth projects into safe mode as a result of the company revising its 2009 capital budget due to market conditions earlier in the year. Safe mode is defined as the costs of deferring the projects and keeping the equipment and facilities in a safe manner in order to expedite remobilization. Pretax safe mode costs of $40 million were incurred in the second quarter of 2009. Total pretax safe mode costs incurred in the first six months of 2009 were $215 million. Based on second quarter costs and expectations for the balance of the year, the outlook for 2009 total safe mode costs has been reduced to between $300 million and $400 million from the previously reported outlook of between $400 million and $500 million.

Depreciation, depletion and amortization (DD&A) expense was $197 million in the second quarter of 2009, compared to $132 million during the same period in 2008. The increase resulted from continued growth in the depreciable cost base for our oil sands facilities.

Alberta Crown royalty expense was $138 million in the second quarter of 2009, compared to $130 million in the second quarter of 2008. The higher expense resulted from increased production, as well as lower operating and capital allowed costs under the New Royalty Framework in 2009. These factors were partially offset by lower prices and the impact of price differentials for bitumen in 2009 compared to synthetic crude oil pricing for 2008. For a further discussion of Crown royalties, see page 8.

Cash flow used in operations was $401 million in the second quarter of 2009, compared to cash flow from operations of $1.174 billion in the second quarter of 2008. The decrease was due primarily to the same factors that impacted earnings.

The net loss for the first six months of 2009 was $417 million, compared to earnings of $1.446 billion in the first six months of 2008. Cash flow used in operations for the first six months of 2009 was $222 million, compared to cash flow from operations of $2.084 billion in the first six months of 2008. The year-to-date decreases in net earnings and cash flow from operations were due primarily to the same factors that impacted second quarter results.

Oil sands production was 301,000 barrels per day (bpd) in the second quarter of 2009, compared to 174,600 bpd during the second quarter of 2008. The increased production in the second quarter of 2009 was primarily due to improved upgrader reliability in the second quarter of 2009. In addition, in the comparative quarter of 2008 a planned maintenance shutdown of one of our upgraders and a regulatory cap on our Firebag in-situ operations impacted production.

Sales volumes during the second quarter of 2009 averaged 285,700 bpd, compared with 181,500 bpd during the second quarter of 2008. The increase was due primarily to increased production. Production volumes processed by Suncor for which a processing fee is received are not included in sales volume totals. The proportion of higher value diesel fuel and sweet crude products decreased to 44% of total sales volumes in the second quarter of 2009, compared to 49% in the second quarter of 2008.

The average price realization for oil sands crude products decreased to $63.93 per barrel in the second quarter of 2009, compared to $121.12 per barrel in the second quarter of 2008. This was primarily due to a significant decrease in the average benchmark WTI crude oil price of about 52%, a discount to WTI on our sweet crude blends and a change in sales mix which reflected a smaller portion of higher priced sweet products. These factors were partially offset by a smaller discount to WTI for our sour crude blends and the positive impact of the weaker Canadian dollar, as we received higher revenues for our production sold based on U.S. dollar benchmark prices

During the second quarter of 2009, cash operating costs averaged $31.30 per barrel, compared to $50.85 per barrel during the second quarter of 2008. The decrease in cash operating costs per barrel was primarily due to the increase in production and a decrease in natural gas input prices. These factors were partially offset by an increase in operational expenses. Cash operating costs per barrel does not include costs related to deferral of growth projects. Refer to page 15 for further details on cash operating costs as a non-GAAP financial measure, including the calculation and reconciliation to GAAP measures.

Oil Sands Growth Update

As previously announced, we deferred the company's growth projects in our revised 2009 capital budget. We do not anticipate any changes to our growth project plans until after the close of the proposed merger with Petro-Canada. At that time, all capital projects from both companies are expected to be reviewed with a view to directing capital investment toward projects with the strongest near-term cash flow potential, highest anticipated return on capital and lowest risk.

During the second quarter of 2009, work continued on the Firebag sulphur plant and the Steepbank extraction plant. The sulphur plant is expected to support sulphur emissions reductions for existing and planned in-situ developments, and the extraction plant is expected to provide improved reliability and productivity for the company's oil sands assets. Both of these projects are scheduled for completion in the third quarter of 2009. The project cost for the Steepbank extraction plant is expected to exceed the previous cost estimate ($850 million +/− 10%) with a final estimated cost of $980 million (+5%) as a result of labour shortages and the resulting productivity challenges, as well as premiums incurred to maintain the project schedule. For an update on our significant capital projects currently in progress see page 11.

Oil Sands Crown Royalties

For a description of the Alberta Crown royalty regimes and rates in effect for our oil sands operations, see page 15 of our 2008 Annual Report.

The following table sets forth an estimation of royalties in the years 2009 through 2013 for three price scenarios, and certain assumptions on which we have based our estimates for those price scenarios.

WTI Price/bbl (US$)	**40**	**60**	**80**
Natural gas (Alberta spot) Cdn$/mcf at AECO	6.50	8.00	9.50
Light/heavy oil differential of WTI at Cushing less Maya at the U.S. Gulf Coast US$	6.50	10.00	13.00
Differential of Maya at the US Gulf Coast less Western Canadian Select at Hardisty, Alberta US$	4.00	4.00	4.00
US$/Cdn$ exchange rate	0.75	0.85	0.95
Crown Royalty Expense (based on percentage of total oil sands revenue) %			
2009 – Bitumen (mining old rates – 25% and 1% min; in-situ new rates)(1)	3-4	4-5	6-7
2010 to 2013 – Bitumen (new rates – with limits for mining only)	1	3-6	6-10

(1) For 2009, 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 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, royalty rates and other changes enacted effective January 1, 2009 by the government of Alberta, current forecasts of production, capital and operating costs, and the forward estimates of commodity prices and exchange rates described in the table.

The following material risk factors could cause actual royalty rates to differ materially from the rates contained in the foregoing table:

(i) The government has enacted new Bitumen Valuation Methodology regulations as part of the implementation of the New Royalty Framework effective January 1, 2009. While the interim bitumen valuation methodology in 2009 has been enacted, the permanent valuation methodology has yet to be finalized. For our mining operations, our January 2008 Royalty Amending Agreement also addresses bitumen valuation methodology (together, the "Bitumen Valuation Requirements"). Accordingly, royalties payable to the Crown is based on an initial interpretation of the Bitumen Valuation Requirements and is subject to further review and may change.

(ii) The government enacted new Allowed Cost 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 our January 2008 Royalty Amending Agreement shelter us through 2015 from the impact of many of these changes for our mining operations. In addition, since our in-situ operations are forecast to remain in pre-payout royalty for the near term, the changes in the Allowed Cost regulations will not have a near term impact on our payment of royalties. However, potential changes and the interpretation of the Allowed Cost regulations could, over time, have a significant impact on our calculation of royalties.

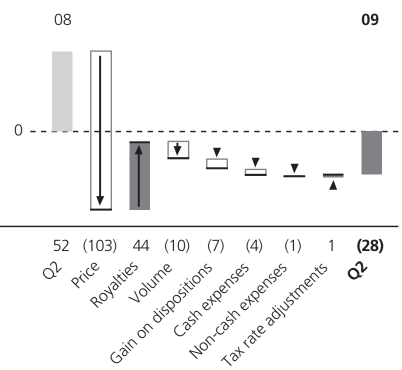
(iii) Changes in crude oil and natural gas pricing, production volumes, foreign exchange rates, and capital and operating costs for each oil sands project; changes resulting from regulatory audits of prior year filings; further changes to applicable royalty regimes by the government of Alberta; changes in other legislation and the occurrence of unexpected events 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 see page 42 of Suncor's AIF dated March 2, 2009.

Natural Gas

Our natural gas business recorded a net loss of $28 million in the second quarter of 2009, compared with net earnings of $52 million during the second quarter of 2008. The net loss was primarily due to reduced revenues resulting from lower benchmark commodity prices and decreased production. These factors were partially offset by a royalty recovery in the second quarter of 2009 compared to royalty expense in the same period of 2008. The decrease in royalties is a result of lower revenues, royalty credits, and reduced rates due to the implementation of the Alberta New Royalty Framework. During the second quarter of 2009, we sold non-core assets for a pretax gain of $15 million. In the second quarter of 2008, we sold non-core assets for a pretax gain of $24 million.

Bridge Analysis of Natural Gas Net Earnings
($ millions)



Cash flow from operations for the second quarter of 2009 was $41 million, compared to $119 million in the second quarter of 2008. The decrease was primarily due to the same factors that affected net earnings, excluding the impact of the gain on sale of non-core assets.

The net loss for the first six months of 2009 was $38 million, compared to net earnings of $71 million in the first six months of 2008. Cash flow from operations for the first six months of 2009 decreased to $96 million from $201 million in the first six months of 2008. The year-to-date decreases in net earnings and cash flow from operations were primarily due to the same factors that impacted second quarter results.

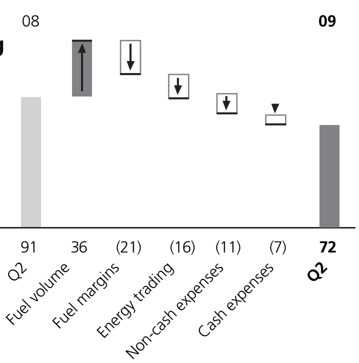
Natural gas and liquids production in the second quarter of 2009 was 211 million cubic feet equivalent (mmcfe) per day, compared to 226 mmcfe per day in the second quarter of 2008. The lower production compared to the prior year was primarily due to natural reservoir declines and shut-in production in the Elmworth area. Our 2009 planned production of 210 mmcfe/day (+5%/−5%) offsets Suncor's projected purchases for internal consumption at our oil sands operations.

Realized natural gas prices in the second quarter of 2009 averaged $3.56 per thousand cubic feet (mcf), compared to an average of $9.62 per mcf in the second quarter of 2009, reflecting significantly lower benchmark prices.

Refining and Marketing

Refining and marketing recorded 2009 second quarter net earnings of $72 million, compared to net earnings of $91 million in the second quarter of 2008. The decrease in net earnings was primarily due to lower diesel margins, as well as asset writedowns resulting from changes in the scope of certain projects. These factors were partially offset by an increase in refined product sales over the second quarter of 2008 (when production was negatively impacted by planned maintenance at our Sarnia refinery), an increase in gasoline margins and improved overall operational reliability.

Bridge Analysis of Refining and Marketing Net Earnings
($ millions)



Energy trading activities resulted in a net pretax loss of $41 million in the second quarter of 2009, compared to $13 million in the second quarter of 2008. This was due primarily to a decrease in earnings on our crude trading activities resulting from mark-to-market losses on financial crude trading activities.

Cash flow from operations was $192 million in the second quarter of 2009, compared to $210 million in the second quarter of 2008. Cash flow from operations decreased primarily due to the same factors affecting net earnings, excluding the asset writedowns.

Our refining and marketing business recorded net earnings of $222 million for the first six months of 2009 compared to $186 million during the first six months of 2008. Cash flow from operations for the first six months of 2008 was $447 million, compared to $400 million in the first six months of 2008. The year-to-date changes in net earnings and cash flow from operations were primarily due to increased refined product sales and higher production at our Sarnia refinery.

The observed performance of our Sarnia refinery in 2008, after completion of our diesel desulphurization and oil sands integration project in 2007, has enabled us to upwardly revise our nameplate capacity to 85,000 bpd from the previously disclosed 70,000 bpd. Effective January 1, 2009, refinery utilization has been calculated using the new capacity. The Commerce City refining capacity has also been increased to 93,000 bpd from 90,000 bpd effective January 1, 2009. During the second quarter of 2009, average daily crude input was 172,600 bpd (97% utilization) compared to 163,700 bpd (102% utilization) in the second quarter of 2008. The average daily crude input was lower in the second quarter of 2008 due to planned maintenance at the Sarnia refinery.

Corporate and Eliminations

After-tax net corporate earnings were $212 million in the second quarter of 2009, compared to net expense of $65 million in the second quarter of 2008. The earnings were mainly due to a larger unrealized foreign exchange gain on our U.S. dollar denominated long-term debt, as the amount by which the Canadian dollar strengthened against the U.S. dollar was greater during the second quarter of 2009 compared to the second quarter of 2008. After-tax unrealized foreign exchange gains on U.S. dollar denominated long-term debt were $405 million in the second quarter of 2009 compared to gains of $18 million in the second quarter of 2008. This was partially offset by higher net interest expense in the second quarter of 2009, as the company expensed $99 million of interest costs that can no longer be capitalized while the growth projects are in safe mode.

Breakdown of Net Corporate Earnings (Expense)

Three months ended June 30 ($ millions)	**2009**	2008
Corporate earnings (expense)	**232**	(42)
Group eliminations	**(20)**	(23)
Total	**212**	(65)

Cash used in operations was $174 million in the second quarter of 2009, compared to $98 million in the second quarter of 2008. The change in cash used in operations was primarily due to the higher net interest expense.

Corporate had net expense of $7 million in the first six months of 2009, compared to net expense of $166 million in the same period of 2008. Cash used in operations was $184 million in the first half of 2009 compared to $119 million in the first half of 2008. The year-to-date changes in after-tax net corporate expense and cash used in operations were due to the same factors that impacted second quarter results.

Cash Income Taxes

We estimate we will have cash income taxes of approximately $350 million to $450 million during 2009. 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 table on page 8, assuming there are no changes to the current income tax regime. Our outlook on cash income tax is a forward looking statement and users of this information are cautioned that actual cash income taxes may vary materially from our outlook.

Analysis of Financial Condition and Liquidity

Our capital resources consist primarily of cash flow from operations and available lines of credit. We believe we will have the capital resources to fund our 2009 capital spending program of $3 billion and to meet current working capital requirements through cash flow from operations and our committed credit facilities, assuming production of 300,000 bpd and a West Texas Intermediate (WTI) price of US$40/bbl. Our cash flow from operations depends on a number of factors, including commodity prices, production/sales levels, downstream margins, operating expenses, taxes, royalties, and US$/Cdn$ exchange rates. If additional capital is required, we believe adequate additional financing will be available in the debt capital markets at commercial terms and rates.

Although benchmark oil prices have strengthened during the second quarter of 2009, we have maintained crude oil hedge contracts through the remainder of 2009 and into 2010 that provide an element of security to our cash flow from operations. For further details on our derivative hedging programs, see page 12.

We continue to closely monitor operational spending, including a freeze on discretionary salary increases, working with vendors to reduce contract rates, as well as implementation of a variety of other cost-cutting measures throughout the company.

During the second quarter of 2009, we renewed our $480 million committed credit facility, extending it one year to the second quarter of 2010 and increasing the total commitment to $855 million.

Management of debt levels continues to be a priority given our long-term growth plans. We believe a phased and flexible approach to existing and future growth projects should assist us in maintaining our ability to manage project costs and debt levels. At June 30, 2009, our net debt (short and long-term debt less cash and cash equivalents) was $9.046 billion, compared to $7.226 billion at December 31, 2008. The increase in debt levels was primarily a result of capital expenditures during the first six months of 2009. Undrawn lines of credit at June 30, 2009 were approximately $1.5 billion.

We are subject to financial and operating covenants related to our 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. We are in compliance with our financial covenant that requires consolidated debt to not be more than 65% of our total capitalization. At June 30, 2009, our consolidated debt to total capitalization was 40% (where consolidated debt is short-term debt plus long-term debt, and total capitalization is consolidated debt plus shareholders' equity). We are also in compliance with all operating covenants.

Excluding cash and cash equivalents, short-term debt, current portion of long-term debt and future income taxes, Suncor had an operating working capital deficiency of $446 million at the end of the second quarter of 2009, compared to a deficiency of $257 million at the end of the second quarter of 2008. The increase in the deficiency was due primarily to a reduction in inventories, partially offset by an increase in income taxes receivable relating to the timing of installment payments.

The preceding paragraphs contain forward-looking information regarding our liquidity and capital resources and users of this information are cautioned that our actual liquidity and capital resources may vary from our expectations.

Significant Capital Project Update

With the deferral of the company's growth projects and the reduction of capital spending announced in January 2009, construction on the Voyageur upgrader and Firebag in-situ facilities has been wound down and the projects placed into safe mode pending resumption of expansion work. At this time, construction restart and completion targets for these projects, and start up and completion targets for other expansion projects, have not been determined. We do not anticipate any changes to our growth project plans until after the close of the proposed merger with Petro-Canada. For a summary of progress on the projects placed into safe mode, please see page 14 of our 2008 Annual Report.

A summary of the progress on our significant projects currently under construction is provided below. All projects listed below have received Board of Director approval. The estimates and target completion dates do not include project commissioning and start-up.

Project	Plan	Cost Estimate $ millions (1)	Estimate % Accuracy (1)	Spent to date	% complete Overall Engineering	% complete Construction	Target completion date
Firebag sulphur plant	Support emission abatement plan at Firebag; capacity to support Stages 1-6	404	+5/−1	380	100	90	Q3 2009
Steepbank extraction plant (2)	New location and technologies aimed at improving operational performance	980	+5	910	100	90	Q3 2009

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

(2) Cost estimate revised to $980 million +5% (previously $850 million +10/−10%).

The preceding paragraphs and table 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 in the table. For a list of the material risk factors that could cause actual timing, amount of the final capital expenditures and expected results to differ materially from those contained in the previous table, please see page 19 of our 2008 Annual Report. For additional information on risks, uncertainties and other factors that could cause actual results to differ, please see page 17.

The material factors 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.

Derivative Financial Instruments

We periodically enter into derivative contracts such as forwards, futures, swaps, options and costless collars to hedge against the potential adverse impact of fluctuating market prices due to changes in the underlying indices.

We have estimated fair values of derivative financial instruments by assessing 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.

Derivative contracts are required to be recorded on the balance sheet at fair value. If the derivative is designated as a cash flow hedge, the effective portions of the changes in fair value of the derivative are initially recorded in other comprehensive income and are recognized in net earnings when the hedged item is recognized. If the derivative is designated as a fair value hedge, changes in the fair value of the derivative and changes in the fair value of the hedged item attributable to the hedged risk are recognized in net earnings. Ineffective portions of changes in the fair value of hedging instruments are recognized in net earnings immediately for both cash flow and fair value hedges.

Suncor also periodically enters into derivative financial instruments that either do not qualify for hedge accounting treatment or that Suncor has not elected to document as part of a qualifying hedge relationship. These financial instruments are accounted for using the mark-to-market method, with any changes in fair value immediately recognized in earnings.

Commodity and Treasury Hedging Activities

The company has hedged a portion of its forecasted U.S. dollar denominated sales subject to U.S. dollar West Texas Intermediate (WTI) price risk. We continue to hold contracts to sell approximately 110,000 barrels per day (bpd) of production at US$50.85 and options to sell 55,000 bpd at an equivalent WTI floor price of US$60.00 for the remainder of 2009.

For the full year 2010, we have crude oil hedges for approximately 50,000 bpd at an equivalent WTI floor price of US$50.00 per barrel and a ceiling price of approximately US$68.00 per barrel. This program replaced previously reported 2010 options to sell 55,000 bpd at an equivalent WTI floor price of US$60.00, which was effectively exited by selling similar contracts in the first quarter of 2009.

These contracts have not been designated for hedge accounting, and as such, any fair value changes on these contracts are recognized in net earnings each period.

In addition to our strategic crude oil hedging program, Suncor uses derivative contracts to hedge risks related to purchases and sales of natural gas and refined products, and to hedge risks specific to individual transactions.

Settlement of our commodity hedging contracts results in cash receipts or payments for the difference between the derivative contract and market rates for the applicable volumes hedged during the contract term. For accounting purposes, amounts received or paid on settlement are recorded as part of the related hedged sales or purchase transactions.

We periodically enter into interest rate swap contracts as part of our strategy to manage exposure to interest rates. The interest rate swap contracts involve an exchange of floating rate and fixed rate interest payments between ourselves and investment grade counterparties. The differentials on the exchange of periodic interest payments are recognized as an adjustment to interest expense. We have recently entered into foreign exchange forward contracts to fix the Canadian dollar value we will receive on future sales of crude oil. Amounts received or paid on settlement will be recorded as part of the related hedged sales transactions.

Significant commodity contracts outstanding at June 30, 2009 were as follows:

Crude Oil	Quantity (bpd)	Price (US$/bbl) [1]	Hedge Period
Purchased puts	55 000	60.00	2009
Fixed price	108 652	50.85	2009
Purchased puts	55 000	60.00	2010
Sold puts	54 753	60.00	2010
Collars – floor	50 041	50.00	2010
Collars – cap	49 986	68.06	2010

(1) Price for crude oil contracts is US$ WTI per barrel at Cushing Oklahoma.

The net earnings impact associated with our commodity and treasury hedging activities in the second quarter of 2009 was a pretax loss of $732 million, compared to a pretax loss of $86 million in the second quarter of 2008. The net earnings impact in the first six months of 2009 was a pretax loss of $952 million, compared to a pretax loss of $99 million in the first six months of 2008.

A reconciliation of changes in accumulated other comprehensive income (AOCI) attributable to derivative hedging activities for the six month period ending June 30 is as follows:

($ millions)	**2009**	2008
AOCI attributable to derivative hedging activities, beginning of the period, net of income taxes of $5 (2008 – $4)	**13**	13
Current year net changes arising from cash flow hedges, net of income taxes of $nil (2008 – $23)	**—**	(57)
Net unrealized hedging losses (gains) at the beginning of the year reclassified to earnings during the period, net of income taxes of $nil (2008 – $1)	**2**	3
AOCI attributable to derivative hedging activities, at June 30, net of income taxes of $5 (2008 – $18)	**15**	(41)

Energy Trading Activities

In addition to derivative contracts used for hedging activities, Suncor uses physical and financial energy derivatives to earn trading revenues. These energy contracts are comprised of crude oil, natural gas and refined products derivative contracts. The results of these trading activities are reported as energy trading revenues and expenses in the Consolidated Statements of Earnings and Comprehensive Income. The net pretax loss associated with our energy trading activities in the second quarter of 2009 was $41 million (2008 – $13 million). The net pretax earnings in the first six months of 2009 were $8 million (2008 – $15 million).

Fair Value of Derivative Financial Instruments

The fair value of derivative financial instruments is the estimated amount we would receive (pay) to terminate the contracts. Such amounts, which also represent the unrealized gain (loss) on the contracts, were as follows:

($ millions)	**June 30 2009**	December 31 2008
Derivative financial instruments accounted for as hedges		
Assets	**26**	24
Liabilities	**—**	(13)
Derivative financial instruments not accounted for as hedges		
Assets	**195**	635
Liabilities	**(946)**	(14)
Net derivative financial instruments	**(725)**	632

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, by their nature, can result in volatile and large positive or negative fluctuations in earnings. A separate risk management function reviews and monitors practices and policies and provides independent verification and valuation of these activities.

Environmental Regulation and Risk

In 2007, the Canadian federal government introduced the Clean Air Act regulatory framework, which is expected to regulate both greenhouse gas emissions and air pollutants from industrial emitters. Suncor has been engaging in the ongoing consultations on this framework. The financial impact of this proposed legislation will be dependent on the details of Clean Air Act regulations, which had been expected to be released by the end of 2008. Now that the Canadian federal government has committed to implement a North American cap and trade system with the United States, it is not certain that the Clean Air Act framework, in its current form, will be implemented.

The Ontario provincial and Colorado state governments are also in various stages of developing greenhouse gas management legislation and regulation. At this time, any potential impacts on pending legislation are unknown.

There remains uncertainty around the outcome and impacts of climate change and other environmental regulations. Depending on the scope of any final regulations, these impacts may have an adverse effect on our operational and financial results in the future. We continue to actively work to mitigate our environmental impact, investing in renewable energy such as wind power and biofuels, accelerating land reclamation, installing new emission abatement equipment and investigating other mitigation opportunities.

In early 2009, a number of frameworks, proposals and directives were issued by the various provincial regulators that oversee oil sands development. These relate to tailings management, water use and land use to name a few. While the financial implications of such directives are yet unknown, Suncor is committed to working with the appropriate regulatory bodies as they develop new policies and to fully comply with all existing and new regulations and directives as they apply to the company's operations. In our recently released 2009 Report on Sustainability, we announced environmental targets for air emissions, land reclamation and water use. For details on these targets, refer to the Report on Sustainability located at www.suncor.com.

Control Environment

Based on their evaluation as of June 30, 2009, our chief executive officer and chief financial officer concluded that our 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 us in reports that we file or submit 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, 2009, there were no changes in our internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) – 15d-15(f)) that occurred during the three and six month periods ended June 30, 2009 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. We will continue to periodically evaluate our disclosure controls and procedures and internal control over financial reporting and will make any modifications from time-to-time as deemed necessary.

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

Change in Accounting Policies

(a) Goodwill and Intangible Assets

On January 1, 2009, the company retroactively adopted Canadian Institute of Chartered Accountants (CICA) Handbook section 3064 "Goodwill and Intangible Assets". This new standard replaces section 3062 "Goodwill and Other Intangible Assets" and section 3450 "Research and Development Costs", and focuses on the criteria for asset recognition in the financial statements, including those internally developed. The impact of adopting this standard resulted in a change in the classification of our deferred maintenance shutdown costs that had previously been classified within other assets and amortized over the period to the next shutdown, as follows:

Change in Consolidated Balance Sheets

($ millions, increase/(decrease))	**As at June 30 2009**	As at December 31 2008
Property, plant and equipment, net	**492**	566
Other assets	**(492)**	(566)

(b) International Financial Reporting Standards

In February 2008, the Accounting Standards Board confirmed that International Financial Reporting Standards (IFRS) will replace Canadian GAAP in 2011 for publicly accountable enterprises. While IFRS uses a conceptual framework similar to Canadian GAAP there are significant differences in accounting policies that must be evaluated.

The company's IFRS conversion project began in 2008. There have been no significant changes in the project from the first quarter of 2009, except for those items noted below. For further information on the IFRS conversion project, please see page 16 of our first quarter 2009 Report to Shareholders.

Financial Statement Preparation
Conclusions have been reached on certain key accounting areas.

Infrastructure
Based on the work to date, no significant IT issues have been identified. Workshops have commenced to discuss key business process and IT changes.

Control Environment
Discussions have been held with Internal Audit to integrate from an internal controls perspective.

Non-GAAP Financial Measures

Certain financial measures referred to in this MD&A, namely cash flow from operations, return on capital employed (ROCE) and oil sands cash and total operating costs per barrel, are not prescribed by 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. Suncor includes these non-GAAP financial measures 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.

Suncor provides a detailed numerical reconciliation of ROCE 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, 2009 interim basis, please refer to page 36.

Cash flow from operations is expressed before changes in non-cash working capital. A reconciliation of net earnings to cash flow from operations is provided in the Schedules of Segmented Data, which are an integral part of Suncor's June 30, 2009 unaudited interim consolidated financial statements.

A reconciliation of cash flow from operations on a per common share basis is presented in the following table:

	Three months ended June 30		Six months ended June 30	
	2009	2008	**2009**	2008
Cash flow from (used in) operations ($ millions)	**(342)**	1 405	**137**	2 566
Weighted number of shares outstanding – basic (millions of shares)	**936.9**	930.5	**936.6**	928.6
Cash flow from operations – basic ($ per share)	**(0.37)**	1.51	**0.15**	2.76

The following tables outline the reconciliation of oil sands cash and total operating costs to expenses included in the Schedules of Segmented Data in the company's financial statements.

Oil Sands Operating Costs – Total Operations

	Three months ended June 30				Six months ended June 30			
	2009		2008		**2009**		2008	
(unaudited)	$ millions	$/barrel	$ millions	$/barrel	$ millions	$/barrel	$ millions	$/barrel
Operating, selling and general expenses	**1 028**		640		**1 937**		1 357	
Less: Natural gas costs, inventory changes, stock-based compensation, and other	**(216)**		(3)		**(213)**		(158)	
Less: Safe mode costs	**(40)**		—		**(215)**		—	
Less: Non-monetary transactions	**(16)**		(30)		**(42)**		(56)	
Accretion of asset retirement obligations	**25**		13		**52**		27	
Taxes other than income taxes	**30**		17		**59**		33	
Cash costs	**811**	**29.65**	637	40.10	**1 578**	**30.15**	1 203	31.30
Natural gas	**45**	**1.65**	139	8.75	**120**	**2.30**	250	6.50
Purchased bitumen (excluding other reported product purchases)	**1**	**—**	32	2.00	**2**	**0.05**	65	1.70
Cash operating costs	**857**	**31.30**	808	50.85	**1 700**	**32.50**	1 518	39.50
Project start-up costs	**10**	**0.35**	14	0.90	**26**	**0.50**	21	0.55
Total cash operating costs	**867**	**31.65**	822	51.75	**1 726**	**33.00**	1 539	40.05
Depreciation, depletion and amortization	**197**	**7.20**	132	8.30	**380**	**7.25**	261	6.80
Total operating costs	**1 064**	**38.85**	954	60.05	**2 106**	**40.25**	1 800	46.85
Production (thousands of barrels per day)	**301.0**		174.6		**289.0**		211.0	

Oil Sands Operating Costs – In-situ Bitumen Production Only

	Three months ended June 30				Six months ended June 30			
	2009		2008		**2009**		2008	
	$ millions	$/barrel	$ millions	$/barrel	$ millions	$/barrel	$ millions	$/barrel
Operating, selling and general expenses	**67**		76		**132**		165	
Less: Natural gas costs	**(24)**		(46)		**(54)**		(91)	
Taxes other than income taxes	**6**		2		**11**		4	
Cash costs	**49**	**11.15**	32	10.10	**89**	**10.80**	78	12.35
Natural gas	**24**	**5.25**	46	14.55	**54**	**6.50**	91	14.40
Cash operating costs	**73**	**16.40**	78	24.65	**143**	**17.30**	169	26.75
In-situ (Firebag) start-up costs	**6**	**1.50**	5	1.65	**19**	**2.35**	6	0.95
Total cash operating costs	**79**	**17.90**	83	26.30	**162**	**19.65**	175	27.70
Depreciation, depletion and amortization	**26**	**6.00**	21	6.70	**53**	**6.45**	43	6.70
Total operating costs	**105**	**23.90**	104	33.00	**215**	**26.10**	218	34.40
Production (thousands of barrels per day)	**48.3**		34.7		**45.4**		34.7	

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 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 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 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 readers are cautioned not to place undue reliance on them.

Suncor's outlook includes a production range of +5%/-10% 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 2009 outlook, see page 3 of our second quarter 2009 report to Shareholders.

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 (for example, the emissions reduction modifications at our Firebag in-situ development); 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; and 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. The foregoing important factors are not exhaustive.

The forward-looking statements and information relating to the proposed transaction between Suncor and Petro-Canada are based on certain key expectations and assumptions made by us, including expectations and assumptions concerning: the accuracy of reserve and resource estimates; customer demand for the merged company's products; commodity prices and interest and foreign exchange rates; planned synergies, capital efficiencies and cost-savings; applicable royalty rates and tax laws; future production rates; the sufficiency of budgeted capital expenditures in carrying out planned activities; the availability and cost of labour and services; and the receipt, in a timely manner, of regulatory and other third party approvals in respect of the proposed merger. In addition, forward-looking statements and information concerning the anticipated completion of the proposed transaction and the anticipated timing for completion of the transaction are provided in reliance on certain assumptions that we believe are reasonable at this time, including; the timing of receipt of the necessary regulatory and other third party approvals; and the time necessary to satisfy the conditions to the closing of the transaction. These dates may change for a number of reasons, including the inability to secure necessary regulatory, court or other third party approvals in the time assumed or the need for additional time to satisfy the conditions to the completion of the transaction. As a result of the foregoing, readers should not place undue reliance on the forward-looking statements and information concerning these times. Although we believe that the expectations and assumptions on which such forward-looking statements and information are based are reasonable, undue reliance should not be placed on the forward-looking statements and information because we can give no assurance that they will prove to be correct.

Since forward-looking statements and information relating to the proposed transaction address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. There are risks also inherent in the nature of the proposed transaction, including: failure to realize anticipated synergies or cost savings; risks regarding the integration of the two entities; incorrect assessments of the values of the other entity; and failure to obtain any required regulatory and other third party approvals (or to do so in a timely manner). The foregoing important factors are not exhaustive.

Many of these risk factors are discussed in further detail throughout this Management's Discussion and Analysis and in the company'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 described in other documents that Suncor files from time to time with securities regulatory authorities. Copies of these documents are available upon request without charge from the company.

Consolidated Statements of Earnings and Comprehensive Income

(unaudited)

($ millions)	Three months ended June 30 2009	Three months ended June 30 2008 (restated) (note 2)	Six months ended June 30 2009	Six months ended June 30 2008 (restated) (note 2)
Revenues (note 3)	**5 058**	7 959	**9 872**	13 947
Expenses				
Purchases of crude oil and products	**1 186**	1 940	**2 034**	3 198
Operating, selling and general (note 7)	**1 290**	886	**2 445**	1 859
Energy trading activities (note 3)	**2 272**	3 264	**4 469**	5 116
Transportation and other costs	**72**	61	**140**	112
Depreciation, depletion and amortization	**311**	252	**613**	500
Accretion of asset retirement obligations	**29**	16	**58**	32
Exploration	**32**	31	**39**	43
Royalties (note 10)	**131**	181	**162**	503
Taxes other than income taxes	**200**	167	**387**	317
Loss (gain) on disposal of assets	**5**	(20)	**22**	(18)
Project start-up costs	**10**	14	**26**	21
Financing expenses (income) (note 5)	**(268)**	6	**(69)**	85
	5 270	6 798	**10 326**	11 768
Earnings (Loss) Before Income Taxes	**(212)**	1 161	**(454)**	2 179
Provisions for (Recovery of) Income Taxes				
Current	**114**	58	**204**	214
Future	**(275)**	274	**(418)**	428
	(161)	332	**(214)**	642
Net Earnings (Loss)	**(51)**	829	**(240)**	1 537
Other comprehensive loss (note 12)	**(96)**	(60)	**(62)**	(13)
Comprehensive Income (Loss)	**(147)**	769	**(302)**	1 524
Net Earnings (Loss) Per Common Share (dollars), (note 6)				
Basic	**(0.06)**	0.89	**(0.26)**	1.66
Diluted	**(0.06)**	0.87	**(0.26)**	1.62
Cash dividends	**0.05**	0.05	**0.10**	0.10

See accompanying notes

Consolidated Balance Sheets

(unaudited)

($ millions)	June 30 2009	December 31 2008 (restated) (note 2)
Assets		
Current assets		
Cash and cash equivalents	**485**	660
Accounts receivable (note 3)	**1 693**	1 580
Inventories	**1 290**	909
Income taxes receivable	**200**	67
Future income taxes	**238**	21
Total current assets	**3 906**	3 237
Property, plant and equipment, net (note 2)	**29 874**	28 882
Other assets (notes 2 and 3)	**234**	409
Total assets	**34 014**	32 528
Liabilities and Shareholders' Equity		
Current liabilities		
Short-term debt	**3**	2
Current portion of long-term debt	**20**	18
Accounts payable and accrued liabilities (note 3)	**3 559**	3 229
Taxes other than income taxes	**63**	97
Income taxes payable	**7**	81
Future income taxes	**26**	111
Total current liabilities	**3 678**	3 538
Long-term debt (note 11)	**9 508**	7 866
Accrued liabilities and other (notes 3 and 8)	**2 134**	1 986
Future income taxes	**4 490**	4 615
Shareholders' equity (see below)	**14 204**	14 523
Total liabilities and shareholders' equity	**34 014**	32 528

Shareholders' Equity

	Number (thousands)		Number (thousands)	
Share capital	**937 131**	**1 140**	935 524	1 113
Contributed surplus		**338**		288
Accumulated other comprehensive income (note 12)		**35**		97
Retained earnings		**12 691**		13 025
Total shareholders' equity		**14 204**		14 523

See accompanying notes

Consolidated Statements of Cash Flows

(unaudited)

($ millions)	Three months ended June 30 2009	2008	Six months ended June 30 2009	2008
Operating Activities				
Cash flow from operations	**(342)**	1 405	**137**	2 566
Decrease (increase) in operating working capital				
Accounts receivable	**(130)**	(27)	**(111)**	(458)
Inventories	**(154)**	(450)	**(381)**	(592)
Accounts payable and accrued liabilities	**842**	295	**1 025**	682
Taxes payable/receivable	**(64)**	(63)	**(241)**	(184)
Cash flow from operating activities	**152**	1 160	**429**	2 014
Cash Used in Investing Activities	**(908)**	(1 778)	**(2 424)**	(3 188)
Net Cash Deficiency Before Financing Activities	**(756)**	(618)	**(1 995)**	(1 174)
Financing Activities				
Increase (decrease) in short-term debt	**—**	(1)	**1**	(1)
Net proceeds from issuance of long-term debt	**—**	2 704	**—**	2 704
Net increase (decrease) in long-term debt	**861**	(694)	**1 898**	(43)
Issuance of common shares under stock option plan	**7**	145	**22**	169
Dividends paid on common shares	**(47)**	(45)	**(94)**	(88)
Cash flow provided by financing activities	**821**	2 109	**1 827**	2 741
Increase (Decrease) in Cash and Cash Equivalents	**65**	1 491	**(168)**	1 567
Effect of Foreign Exchange on Cash and Cash Equivalents	**(11)**	(2)	**(7)**	10
Cash and Cash Equivalents at Beginning of Period	**431**	657	**660**	569
Cash and Cash Equivalents at End of Period	**485**	2 146	**485**	2 146

See accompanying notes

Consolidated Statements of Changes in Shareholders' Equity

(unaudited)

($ millions)	Share Capital	Contributed Surplus	Accumulated Other Comprehensive Income (AOCI)	Retained Earnings
At December 31, 2007	881	194	(253)	11 074
Net earnings	—	—	—	1 537
Dividends paid on common shares	—	—	—	(88)
Issued for cash under stock option plan	200	(31)	—	—
Issued under dividend reinvestment plan	4	—	—	(4)
Stock-based compensation expense	—	69	—	—
Income tax benefit of stock option deduction in the U.S.	—	4	—	—
Change in AOCI related to foreign currency translation	—	—	41	—
Change in AOCI related to derivative hedging activities	—	—	(54)	—
At June 30, 2008	1 085	236	(266)	12 519
At December 31, 2008	1 113	288	97	13 025
Net earnings (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 AOCI related to foreign currency translation	**—**	**—**	**(64)**	**—**
Change in AOCI related to derivative hedging activities	**—**	**—**	**2**	**—**
At June 30, 2009	**1 140**	**338**	**35**	**12 691**

See accompanying notes

Schedules of Segmented Data

(unaudited)

Three months ended June 30

($ millions)	Oil Sands 2009	Oil Sands 2008	Natural Gas 2009	Natural Gas 2008	Refining and Marketing 2009	Refining and Marketing 2008	Corporate and Eliminations 2009	Corporate and Eliminations 2008	Total 2009	Total 2008
EARNINGS										
Revenues										
Operating revenues	**830**	1 738	**67**	209	**1 924**	2 779	**4**	5	**2 825**	4 731
Energy trading activities	**—**	—	**—**	—	**2 233**	3 253	**(1)**	(32)	**2 232**	3 221
Intersegment revenues	**369**	429	**7**	20	**—**	—	**(376)**	(449)	**—**	—
Interest	**—**	—	**—**	—	**—**	—	**1**	7	**1**	7
	1 199	2 167	**74**	229	**4 157**	6 032	**(372)**	(469)	**5 058**	7 959
Expenses										
Purchases of crude oil and products	**164**	114	**—**	—	**1 365**	2 242	**(343)**	(416)	**1 186**	1 940
Operating, selling and general	**1 028**	640	**38**	39	**167**	182	**57**	25	**1 290**	886
Energy trading activities	**—**	—	**—**	—	**2 274**	3 266	**(2)**	(2)	**2 272**	3 264
Transportation and other costs	**59**	50	**6**	4	**7**	7	**—**	—	**72**	61
Depreciation, depletion and amortization	**197**	132	**54**	52	**55**	57	**5**	11	**311**	252
Accretion of asset retirement obligations	**25**	13	**3**	2	**1**	1	**—**	—	**29**	16
Exploration	**—**	—	**32**	31	**—**	—	**—**	—	**32**	31
Royalties (note 10)	**138**	130	**(7)**	51	**—**	—	**—**	—	**131**	181
Taxes other than income taxes	**34**	26	**3**	3	**162**	137	**1**	1	**200**	167
Loss (gain) on disposal of assets	**—**	2	**(15)**	(24)	**20**	2	**—**	—	**5**	(20)
Project start-up costs	**10**	14	**—**	—	**—**	—	**—**	—	**10**	14
Financing expenses (income)	**—**	—	**—**	—	**—**	—	**(268)**	6	**(268)**	6
	1 655	1 121	**114**	158	**4 051**	5 894	**(550)**	(375)	**5 270**	6 798
Earnings (loss) before income taxes	**(456)**	1 046	**(40)**	71	**106**	138	**178**	(94)	**(212)**	1 161
Income taxes	**149**	(295)	**12**	(19)	**(34)**	(47)	**34**	29	**161**	(332)
Net earnings (loss)	**(307)**	751	**(28)**	52	**72**	91	**212**	(65)	**(51)**	829

Schedules of Segmented Data (continued)

(unaudited)

Three months ended June 30

($ millions)	Oil Sands 2009	Oil Sands 2008	Natural Gas 2009	Natural Gas 2008	Refining and Marketing 2009	Refining and Marketing 2008	Corporate and Eliminations 2009	Corporate and Eliminations 2008	Total 2009	Total 2008
CASH FLOW BEFORE FINANCING ACTIVITIES										
Cash flow from (used in) operating activities:										
Cash flow from (used in) operations										
Net earnings (loss)	**(307)**	751	**(28)**	52	**72**	91	**212**	(65)	**(51)**	829
Exploration expenses	**—**	—	**31**	29	**—**	—	**—**	—	**31**	29
Non-cash items included in earnings										
Depreciation, depletion and amortization	**197**	132	**54**	52	**55**	57	**5**	11	**311**	252
Future income taxes	**(309)**	231	**(5)**	13	**45**	49	**(6)**	(19)	**(275)**	274
Loss (gain) on disposal of assets	**—**	2	**(15)**	(24)	**20**	2	**—**	—	**5**	(20)
Stock-based compensation expense	**13**	13	**1**	—	**4**	4	**6**	8	**24**	25
Other	**7**	8	**3**	(3)	**3**	5	**(387)**	(32)	**(374)**	(22)
Increase (decrease) in deferred credits and other	**(2)**	37	**—**	—	**(7)**	2	**(4)**	(1)	**(13)**	38
Total cash flow from (used in) operations	**(401)**	1 174	**41**	119	**192**	210	**(174)**	(98)	**(342)**	1 405
Decrease (increase) in operating working capital	**874**	(664)	**(17)**	(105)	**(316)**	274	**(47)**	250	**494**	(245)
Total cash flow from (used in) operating activities	**473**	510	**24**	14	**(124)**	484	**(221)**	152	**152**	1 160
Cash from (used in) investing activities:										
Capital and exploration expenditures	**(522)**	(1 798)	**(81)**	(40)	**(28)**	(26)	**—**	(5)	**(631)**	(1 869)
Deferred outlays and other investments	**(1)**	(25)	**—**	—	**—**	1	**(18)**	2	**(19)**	(22)
Proceeds from disposals	**—**	—	**27**	25	**—**	—	**—**	—	**27**	25
Decrease (increase) in investing working capital	**(283)**	89	**—**	—	**—**	(1)	**(2)**	—	**(285)**	88
Total cash (used in) investing activities	**(806)**	(1 734)	**(54)**	(15)	**(28)**	(26)	**(20)**	(3)	**(908)**	(1 778)
Net cash surplus (deficiency) before financing activities	**(333)**	(1 224)	**(30)**	(1)	**(152)**	458	**(241)**	149	**(756)**	(618)

Schedules of Segmented Data

(unaudited)

Six months ended June 30

($ millions)	Oil Sands 2009	Oil Sands 2008	Natural Gas 2009	Natural Gas 2008	Refining and Marketing 2009	Refining and Marketing 2008	Corporate and Eliminations 2009	Corporate and Eliminations 2008	Total 2009	Total 2008
EARNINGS										
Revenues										
Operating revenues	**1 775**	3 683	**166**	371	**3 443**	4 801	**9**	10	**5 393**	8 865
Energy trading activities	**—**	—	**—**	—	**4 480**	5 134	**(2)**	(65)	**4 478**	5 069
Intersegment revenues	**540**	730	**22**	30	**—**	—	**(562)**	(760)	**—**	—
Interest	**—**	—	**—**	—	**—**	—	**1**	13	**1**	13
	2 315	4 413	**188**	401	**7 923**	9 935	**(554)**	(802)	**9 872**	13 947
Expenses										
Purchases of crude oil and products	**226**	161	**—**	—	**2 323**	3 795	**(515)**	(758)	**2 034**	3 198
Operating, selling and general	**1 937**	1 357	**80**	79	**342**	357	**86**	66	**2 445**	1 859
Energy trading activities	**—**	—	**—**	—	**4 472**	5 119	**(3)**	(3)	**4 469**	5 116
Transportation and other costs	**116**	92	**11**	7	**13**	13	**—**	—	**140**	112
Depreciation, depletion and amortization	**380**	261	**110**	110	**111**	108	**12**	21	**613**	500
Accretion of asset retirement obligations	**52**	27	**5**	4	**1**	1	**—**	—	**58**	32
Exploration	**6**	9	**33**	34	**—**	—	**—**	—	**39**	43
Royalties (note 10)	**146**	412	**16**	91	**—**	—	**—**	—	**162**	503
Taxes other than income taxes	**71**	53	**3**	3	**312**	260	**1**	1	**387**	317
Loss (gain) on disposal of assets	**17**	2	**(15)**	(24)	**20**	4	**—**	—	**22**	(18)
Project start-up costs	**26**	21	**—**	—	**—**	—	**—**	—	**26**	21
Financing expenses (income)	**—**	—	**—**	—	**—**	—	**(69)**	85	**(69)**	85
	2 977	2 395	**243**	304	**7 594**	9 657	**(488)**	(588)	**10 326**	11 768
Earnings (loss) before income taxes	**(662)**	2 018	**(55)**	97	**329**	278	**(66)**	(214)	**(454)**	2 179
Income taxes	**245**	(572)	**17**	(26)	**(107)**	(92)	**59**	48	**214**	(642)
Net earnings (loss)	**(417)**	1 446	**(38)**	71	**222**	186	**(7)**	(166)	**(240)**	1 537
As at June 30										
TOTAL ASSETS	**27 390**	21 181	**1 868**	1 939	**4 944**	5 995	**(188)**	978	**34 014**	30 093

Schedules of Segmented Data (continued)

(unaudited)

Six months ended June 30

($ millions)	Oil Sands 2009	Oil Sands 2008	Natural Gas 2009	Natural Gas 2008	Refining and Marketing 2009	Refining and Marketing 2008	Corporate and Eliminations 2009	Corporate and Eliminations 2008	Total 2009	Total 2008
CASH FLOW BEFORE FINANCING ACTIVITIES										
Cash flow from (used in) operating activities:										
Cash flow from (used in) operations										
Net earnings (loss)	**(417)**	1 446	**(38)**	71	**222**	186	**(7)**	(166)	**(240)**	1 537
Exploration expenses	**—**	—	**31**	29	**—**	—	**—**	—	**31**	29
Non-cash items included in earnings										
Depreciation, depletion and amortization	**380**	261	**110**	110	**111**	108	**12**	21	**613**	500
Future income taxes	**(531)**	366	**1**	16	**86**	80	**26**	(34)	**(418)**	428
Loss (gain) on disposal of assets	**17**	2	**(15)**	(24)	**20**	4	**—**	—	**22**	(18)
Stock-based compensation expense	**27**	35	**2**	2	**8**	11	**14**	21	**51**	69
Other	**(4)**	(16)	**5**	(3)	**7**	10	**(226)**	40	**(218)**	31
Increase (decrease) in deferred credits and other	**306**	(10)	**—**	—	**(7)**	1	**(3)**	(1)	**296**	(10)
Total cash flow from (used in) operations	**(222)**	2 084	**96**	201	**447**	400	**(184)**	(119)	**137**	2 566
Decrease (increase) in operating working capital	**(182)**	(464)	**(16)**	(64)	**(250)**	164	**740**	(188)	**292**	(552)
Total cash flow from (used in) operating activities	**(404)**	1 620	**80**	137	**197**	564	**556**	(307)	**429**	2 014
Cash from (used in) investing activities:										
Capital and exploration expenditures	**(1 479)**	(3 108)	**(190)**	(166)	**(60)**	(75)	**—**	(9)	**(1 729)**	(3 358)
Deferred outlays and other investments	**(26)**	(31)	**—**	—	**—**	—	**(18)**	(2)	**(44)**	(33)
Proceeds from disposals	**—**	—	**27**	25	**—**	—	**—**	—	**27**	25
Decrease (increase) in investing working capital	**(678)**	191	**—**	—	**—**	(13)	**—**	—	**(678)**	178
Total cash (used in) investing activities	**(2 183)**	(2 948)	**(163)**	(141)	**(60)**	(88)	**(18)**	(11)	**(2 424)**	(3 188)
Net cash surplus (deficiency) before financing activities	**(2 587)**	(1 328)	**(83)**	(4)	**137**	476	**538**	(318)	**(1 995)**	(1 174)

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, except for the accounting policy change as described in note 2, Change in Accounting Policies. 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, 2009 and the results of its operations and cash flows for the three and six month periods ended June 30, 2009 and 2008.

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

2. CHANGE IN ACCOUNTING POLICIES

Goodwill and Intangible Assets

On January 1, 2009, the company retroactively adopted Canadian Institute of Chartered Accountants (CICA) Handbook section 3064 "Goodwill and Intangible Assets". This new standard replaces section 3062 "Goodwill and Other Intangible Assets" and section 3450 "Research and Development Costs", and focuses on the criteria for asset recognition in the financial statements, including those internally developed. The impact of adopting this standard resulted in a change in the classification of our deferred maintenance shutdown costs that had previously been classified within other assets and amortized over the period to the next shutdown, as follows:

Change in Consolidated Balance Sheets

($ millions, increase/(decrease))	**As at June 30 2009**	As at December 31 2008
Property, plant and equipment, net	**492**	566
Other assets	**(492)**	(566)

3. 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 (hedge) 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.

Forwards and futures are contracts to purchase or sell a specific item at a specified date and price. When used as hedges, forwards and futures help to manage the exposure to losses that could result if commodity prices or foreign currency exchange rates change adversely.

An option is a contract where its holder, for a fee, has purchased the right (but not the obligation) to buy or sell a specified item at a fixed price during a specified period. Options used as hedges help to protect against adverse changes in commodity prices, interest rates, or foreign currency exchange rates.

A costless collar is a combination of two option contracts that limit the holder's exposure to changes in prices to within a specific range. The "costless" nature of this derivative is achieved by buying a put option (the right to sell) for consideration equal to the premium received from selling a call option (the right to purchase).

A swap is a contract where two parties exchange commodity, currency, interest or other payments in order to alter the nature of the payments. For example, fixed interest rate payments on debt may be converted to payments based on a floating interest rate, or vice versa; a domestic currency debt may be converted to a foreign currency debt.

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 has elected to use hedge accounting on certain derivatives linked to future commodity and financial transactions.

See below for more technical details and amounts.

(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 (except for the current portions of asset retirement and pension obligations and future income tax), and long-term debt. 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's fixed-term debt is accounted for under the amortized cost method. Upon initial recognition, the cost of the debt is its fair value, adjusted for any associated transaction costs. We do 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, 2009, the carrying value of our fixed-term debt accounted for under the amortized cost method was $6.4 billion (December 31, 2008 – $6.7 billion) and the fair value was $6.2 billion (December 31, 2008 – $5.4 billion).

(b) Hedges – documented as part of a qualifying hedge relationship

Fair Value Hedges

At June 30, 2009, the company had interest rate swaps classified as fair value hedges outstanding until August 2011, relating to fixed-rate debt. There was no ineffectiveness recognized on interest rate swaps designated as fair value hedges during the three and six month periods ended June 30, 2009 and June 30, 2008.

The earnings impact associated with hedge ineffectiveness on derivative contracts to hedge risks specific to individual transactions during the three month period ended June 30, 2009 was a gain of $2 million net of income taxes of $1 million (2008 – loss of $2 million, net of income taxes of $1 million). During the six month period ended June 30, 2009, the earnings impact was a gain of $3 million, net of income taxes of $1 million (2008 – loss of $3 million, net of income taxes of $1 million).

Cash Flow Hedges

At June 30, 2009, the company had hedged a portion of its forecasted cash flows subject to natural gas price risk. There was no earnings impact associated with realized and unrealized hedge ineffectiveness on derivative contracts designated as cash flow hedges during the three and six month periods ended June 30, 2009 and June 30, 2008.

Fair Value of Hedging Derivative Financial Instruments

The fair value of hedging derivative financial instruments as recorded, is the estimated amount that the company would receive (pay) to terminate the hedging derivative contracts. Such amounts, which also represent the unrealized gain (loss) on the contracts, were as follows:

($ millions)	**June 30 2009**	December 31 2008
Revenue hedge swaps and collars	**1**	(2)
Fixed to floating interest rate swaps	**21**	24
Specific hedges of individual transactions	**4**	(11)
Fair value of outstanding hedging derivative financial instruments	**26**	11

Accumulated Other Comprehensive Income (AOCI)

A reconciliation of changes in AOCI attributable to derivative hedging activities for the six month periods ending June 30 is as follows:

($ millions)	**2009**	**2008**
AOCI attributable to derivative hedging activities, beginning of the period, net of income taxes of $5 (2008 – $4)	**13**	13
Current period net changes arising from cash flow hedges, net of income taxes of $nil (2008 – $23)	**—**	(57)
Net unrealized hedging losses at the beginning of the year reclassified to earnings during the period, net of income taxes of $nil (2008 – $1)	**2**	3
AOCI attributable to derivative hedging activities, at June 30, net of income taxes of $5 (2008 – $18)	**15**	(41)

(c) Hedges – Not Documented as Part of a Qualifying Hedge Relationship

The company also periodically enters into derivative financial instruments such as options, basis swaps, and heat rate swaps that either do not qualify for hedge accounting treatment or hedges that the company has not elected to document as part of a qualifying hedge relationship. The earnings impact associated with these contracts for the three month period ended June 30, 2009, was a loss of $542 million, net of income taxes of $199 million (2008 – a loss of $50 million, net of income taxes of $20 million). During the six month period ended June 30, 2009, the earnings impact was a loss of $690 million net of income taxes of $258 million (2008 – a loss of $60 million, net of income taxes of $24 million).

Significant contracts outstanding at June 30 were as follows:

Crude oil	Quantity (bpd)	Average Price [1] (US$/bbl)	Hedge Period
Purchased puts [2]	55 000	60.00	2009
Fixed price	108 652	50.85	2009
Purchased puts [2]	55 000	60.00	2010
Sold puts [3]	54 753	60.00	2010
Collars – floor	50 041	50.00	2010
Collars – cap	49 986	68.06	2010

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

(2) Total premium paid was US$59 million.

(3) Premium received was US$213 million.

(d) Energy Trading Activities

In addition to the financial derivatives used for hedging activities, the company uses physical and financial energy contracts, including swaps, forwards and options to earn trading revenues. Physical energy trading contracts involve activities intended to enhance prices and satisfy physical deliveries to customers. Net pretax earnings for the three and six month periods ended June 30, as recorded in our refining and marketing segment, were as follows:

Net Pretax Earnings (Loss)

	Three months ended June 30		Six months ended June 30	
($ millions)	**2009**	2008	**2009**	2008
Physical energy contracts trading activity	**(33)**	(18)	**18**	12
Financial energy contracts trading activity	**(6)**	8	**(5)**	8
General and administrative costs	**(2)**	(3)	**(5)**	(5)
Total	**(41)**	(13)	**8**	15

(e) Fair Value of Non-Designated Derivative Financial Instruments

The fair value of unsettled (unrealized) non-designated derivative financial instruments, which includes all contracts referenced in section (c) & (d) above are as follows:

($ millions)	**June 30 2009**	December 31 2008
Derivative financial instrument assets (1)	**195**	635
Derivative financial instrument liabilities (2)	**946**	14
Net assets (liabilities)	**(751)**	621

(1) As at June 30, 2009, $122 million is recorded in accounts receivable (December 31, 2008 – $376 million) and $73 million is recorded in other assets (December 31, 2008 – $259 million) in the Consolidated Balance Sheets.

(2) As at June 30, 2009, $728 million is recorded in accounts payable and accrued liabilities (December 31, 2008 – $14 million) and $218 million is recorded in accrued liabilities and other in the Consolidated Balance Sheets.

Change in fair value of net assets

($ millions)	**2009**
Fair value of contracts at December 31, 2008	621
Fair value of contracts realized during the period	**(61)**
Fair value of contracts entered into during the period	**(953)**
Changes in values attributable to market price and other market changes during the period	**(358)**
Fair value of contracts outstanding at June 30, 2009	**(751)**

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 risk management 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, 2009, the company's exposure to risks associated arising from the use of financial instruments had not changed significantly from December 31, 2008.

Changes in commodity prices on our financial contracts would have the following impact on our net earnings and other comprehensive income for the three months ended June 30, 2009:

Financial Instrument Sensitivity Analysis

($ millions)	June 30, 2009 (1)	Change	Net Earnings	Other Comprehensive Income
Crude Oil	US$76.66/barrel			
Price increase		US$1.00/barrel	(30)	—
Price decrease		US$1.00/barrel	30	—
Natural Gas	US$5.50/mcf			
Price increase		US$0.10/mcf	(1)	—
Price decrease		US$0.10/mcf	1	—

(1) Prices represent the average of the forward strip prices at June 30, 2009.

For full discussion of the company's financial risk factors, see page 67 of our 2008 Annual Report.

4. 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 and total debt to total debt plus shareholders' equity.

Net debt to cash flow from operations is calculated as short-term debt plus 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 long-term debt divided by short-term debt plus long-term debt plus shareholders' equity.

The company's strategy during the second quarter of 2009, which was unchanged from 2008, was to maintain the measure set out in the following schedule. The company believes that maintaining our capital target helps to provide the company access to capital at a reasonable cost by maintaining solid investment-grade credit ratings. The company operates in a cyclical business environment and ratios may periodically fall outside of management targets.

At June 30, ($ millions)	Capital Measure Target	**2009**	2008
Components of ratios			
Short-term debt		**3**	2
Current portion of long-term debt		**20**	4
Long-term debt		**9 508**	6 547
Total debt		**9 531**	6 553
Cash and equivalents		**485**	2 146
Net debt		**9 046**	4 407
Shareholders' equity		**14 204**	13 574
Total capitalization (total debt + shareholders' equity)		**23 735**	20 127
Cash flow from operations (trailing twelve months)		**2 034**	4 723
Net debt/cash flow from operations	< 2.0 times	**4.4**	0.9
Total debt/total debt plus shareholders' equity		**40%**	33%

5. FINANCING EXPENSES (INCOME)

($ millions)	Three months ended June 30 2009	2008	Six months ended June 30 2009	2008
Interest expense on debt	**117**	77	**235**	141
Capitalized interest	**(18)**	(77)	**(72)**	(141)
Net interest expense	**99**	—	**163**	—
Foreign exchange (gain) loss on long-term debt	**(405)**	(21)	**(257)**	65
Other foreign exchange loss	**38**	27	**25**	20
Total financing expenses (income)	**(268)**	6	**(69)**	85

6. RECONCILIATION OF BASIC AND DILUTED EARNINGS PER COMMON SHARE

($ millions)	Three months ended June 30 2009	2008	Six months ended June 30 2009	2008
Net earnings (loss)	**(51)**	829	**(240)**	1 537
(millions of common shares)				
Weighted-average number of common shares	**937**	931	**937**	929
Dilutive securities:				
Options issued under stock-based compensation plans	**10**	22	**9**	19
Weighted-average number of diluted common shares	**947**	953	**946**	948
(dollars per common share)				
Basic earnings (loss) per share [a]	**(0.06)**	0.89	**(0.26)**	1.66
Diluted earnings (loss) per share [b]	**(0.06)**	0.87	**(0.26)**	1.62

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.

7. STOCK-BASED COMPENSATION

A common share option gives the holder the right, but not the obligation, to purchase common shares at a predetermined price over a specified period of time.

After the date of grant, employees and non-employee directors that hold options must earn the right to exercise them. This is done by the holder fulfilling a time requirement for service to the company, and with respect to certain options, is subject to accelerated vesting should the company meet predetermined performance criteria. Once this right has been earned, these options are considered vested.

The predetermined price at which an option can be exercised is equal to or greater than the market price of the common shares on the date the option is granted.

A performance vesting share unit is an award entitling employees to receive cash to varying degrees contingent upon the company's shareholder return relative to a peer group of companies.

A restricted share unit is a time-vested award with a three-year term entitling employees to receive cash.

(a) Stock Option Plans:

(i) SunShare 2012 Performance Stock Option Plan

The company granted 468,000 options in the second quarter of 2009, for a total of 961,000 options granted in the six months ended June 30, 2009 (826,000 options granted during the second quarter of 2008; 1,056,000 options granted during in the six months ended June 30, 2008) to all eligible permanent full-time and part-time employees, both executive and non-executive, under its SunShare 2012 performance stock option plan. During 2008, in connection with the achievement of a predetermined performance criterion, 25% of the outstanding options vested under the SunShare 2012 plan and will become exercisable on January 1, 2010. The remaining 75% of outstanding options may vest on January 1, 2013 if further specified performance targets are met. All unvested options which have not previously expired or been cancelled will automatically expire on January 1, 2013.

(ii) Executive Stock Plan

The company did not grant options under this plan in the second quarter of 2009. A total of 711,000 options were granted in the six months ended June 30, 2009 (26,000 options granted during the second quarter of 2008; 828,000 granted in the six months ended June 30, 2008) to non-employee directors and certain executives and other senior members of the company. Options granted have a ten-year life and vest annually over a three-year period.

(iii) Key Contributor Stock Option Plan

Under this plan, the company granted 4,000 common share options in the second quarter of 2009, for a total of 569,000 options granted in the six months ended June 30, 2009 (22,000 options granted during the second quarter of 2008; 2,362,000 granted in the six months ended June 30, 2008) to non-insider senior managers and key employees. Options granted have a ten-year life and vest annually over a three-year period.

Fair Value of Options Granted

The fair values of all common share options granted during the period are estimated as at the grant date using the Monte Carlo simulation approach for the SunShare 2012 option plan and the Black-Scholes option-pricing model for all other option plans. The weighted-average fair values of the options granted during the various periods and the weighted-average assumptions used in their determination are as noted below:

	Three months ended June 30		Six months ended June 30	
	2009	2008	**2009**	2008
Quarterly dividend per share	**$0.05**	$0.05	**$0.05**	$0.05
Risk-free interest rate	**1.74%**	3.06%	**2.08%**	3.51%
Expected life	**4 years**	5 years	**5 years**	6 years
Expected volatility	**52%**	30%	**42%**	28%
Weighted-average fair value per option	**$7.64**	$12.80	**$8.86**	$15.07

Expense recognized in the second quarter of 2009 related to stock option plans was $24 million (2008 – $25 million). For the six months ended June 30, 2009, expense recognized was $51 million (2008 – $69 million).

(b) Performance Share Units (PSUs)

In the second quarter of 2009, the company issued 4,000 PSUs (2008 – 18,000). For the six months ended June 30, 2009, the company issued 1,145,000 PSUs (2008 – 780,000). Expense recognized in the second quarter of 2009 was $2 million (2008 – $15 million). Expense recognized for the six months ended June 30, 2009 was $10 million (2008 – $10 million).

(c) Restricted Share Units (RSUs)

(i) SunShare 2012 Restricted Share Units

In the second quarter of 2009, the company issued 18,000 RSUs (2008 – 46,000). For the six months ended June 30, 2009, the company issued 47,000 RSUs (2008 – 976,000). Expense recognized in the second quarter of 2009 was $5 million (2008 – $5 million). Expense recognized for the six months ended June 30, 2009 was $9 million (2008 – $9 million).

(ii) Restricted Share Unit Plan

The company issued 6,000 RSUs in the second quarter of 2009 and 1,568,000 RSUs in the six months ended June 30, 2009 to non-insider senior managers and key employees under its new restricted share unit plan. Expense recognized in the second quarter of 2009 was $7 million, and expense recognized for the six months ended June 30, 2009 was $16 million.

8. EMPLOYEE FUTURE BENEFITS LIABILITY

The company's pension plans and other post-retirement benefits programs are described in note 10 of the company's 2008 Annual Report. The following is the status of the net periodic benefit cost for the three and six months ended June 30.

				Pension Benefits
	Three months ended June 30		Six months ended June 30	
	2009	2008	**2009**	2008
Current service costs	**13**	14	**26**	28
Interest costs	**13**	12	**26**	24
Expected return on plan assets	**(10)**	(11)	**(20)**	(22)
Amortization of net actuarial loss	**5**	5	**10**	11
Net periodic benefit cost	**21**	20	**42**	41

				Other Post-Retirement Benefits
	Three months ended June 30		Six months ended June 30	
	2009	2008	**2009**	2008
Current service costs	**2**	1	**3**	2
Interest costs	**3**	3	**5**	5
Amortization of net actuarial loss	**—**	—	**—**	1
Net periodic benefit cost	**5**	4	**8**	8

9. SUPPLEMENTAL INFORMATION

	Three months ended June 30		Six months ended June 30	
($ millions)	**2009**	2008	**2009**	2008
Interest paid	**173**	58	**234**	124
Income taxes paid	**155**	131	**395**	404

10. ROYALTIES

For a description of the Alberta Crown royalty regimes in effect for our oil sands operations, see page 15 of our 2008 Annual Report.

Our current estimation of Alberta Crown royalties is based on regulations and crown agreements currently in effect. Alberta Crown royalties in effect for each of our oil sands projects require payments to the Government of Alberta based on annual gross revenues less related transportation costs (R) less allowable costs (C), including the deduction of certain capital expenditures at 25% to 40% (the R-C Royalty), subject to a minimum payment of 1% to 9% of R (the Minimum Royalty).

Changes in bitumen 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; changes in legislation and the occurrence of unexpected events all have the potential to have an impact on oil sands royalties payable to the Crown.

The oil sands royalty expense was $146 million for the first six months of 2009, compared to $412 million for the first six months of 2008. The lower expense was due to a significant decrease in price realizations in the first six months of 2009 relative to 2008. In addition, effective January 1, 2009, revenues from our base mine operations are now based on bitumen values (previously based on synthetic crude oil) with a corresponding exclusion of upgrading costs from royalty eligibility. With higher prices in the second quarter than in the first, royalties for the six months of 2009 have reverted back to 25% of R minus C (for our base mining operation) versus the 1% minimum royalty reported in the first quarter of 2009.

The balance of the consolidated royalty expense is in respect of natural gas royalties of $16 million (2008 – $91 million).

11. LONG-TERM DEBT AND CREDIT FACILITIES

($ millions)	June 30 2009	December 31 2008
Fixed-term debt, redeemable at the option of the Company		
6.85% Notes, denominated in U.S. dollars, due in 2039 (US$750)	**872**	918
6.50% Notes, denominated in U.S. dollars, due in 2038 (US$1150)	**1 337**	1 408
5.95% Notes, denominated in U.S. dollars, due in 2034 (US$500)	**581**	612
7.15% Notes, denominated in U.S. dollars, due in 2032 (US$500)	**581**	612
6.10% Notes, denominated in U.S. dollars, due in 2018 (US$1250)	**1 453**	1 531
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 2011	**500**	500
	6 624	6 881
Revolving-term debt, with interest at variable rates		
Commercial paper and bankers' acceptances	**2 832**	934
Total unsecured long-term debt	**9 456**	7 815
Secured long-term debt	**13**	13
Capital leases	**103**	103
Fair value of interest swaps	**21**	25
Deferred financing costs	**(65)**	(72)
	9 528	7 884
Current portion		
Capital leases	**(9)**	(9)
Fair value of interest swaps	**(11)**	(9)
Total current portion	**(20)**	(18)
Total long-term debt	**9 508**	7 866

At June 30, 2009, undrawn lines of credit were approximately $1,453 million, as follows:

($ millions)	2009
Facility that is fully revolving for 364 days, has a term period of one year and expires in 2010	**855**
Facility that is fully revolving for a period of five years and expires in 2013	**3 750**
Facilities that can be terminated at any time at the option of the lenders	**38**
Total available credit facilities	**4 643**
Credit facilities supporting outstanding commercial paper and bankers' acceptances	**2 832**
Credit facilities supporting standby letters of credit	**358**
Total undrawn credit facilities	**1 453**

12. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

($ millions)	**June 30 2009**	December 31 2008
Unrealized foreign currency translation adjustments	**20**	84
Unrealized gains and losses on derivative hedging activities	**15**	13
Total	**35**	97

13. PETRO-CANADA MERGER

On March 23, 2009, Suncor and Petro-Canada (TSX:PCA) (NYSE:PCZ) announced that they have agreed to merge the two companies. The merger has received shareholder, court and Competition Bureau approval and with all the conditions necessary to complete the transaction satisfied, Suncor and Petro-Canada intend to make the merger effective August 1, 2009. The combined entity will operate corporately and trade under the Suncor name while maintaining the strong brand presence and customer loyalty of Petro-Canada in refined products.

Highlights

(unaudited)

	2009	2008
Cash Flow from Operations		
(dollars per common share – basic)		
For the three months ended June 30		
Cash flow from operations (1)	**(0.37)**	1.51
For the six months ended June 30		
Cash flow from operations (1)	**0.15**	2.76
Ratios		
For the twelve months ended June 30		
Return on capital employed (%) (2)	**7.3**	28.8
Return on capital employed (%) (3)	**5.0**	20.7
Net debt to cash flow from operations (times) (4)	**4.4**	0.9
Interest coverage on long-term debt (times)		
Net earnings (5)	**1.5**	15.9
Cash flow from operations (6)	**6.1**	20.3
As at June 30		
Debt to debt plus shareholders' equity (%) (7)	**40.2**	32.6
Common Share Information		
As at June 30		
Share price at end of trading		
Toronto Stock Exchange – Cdn$	**35.37**	59.20
New York Stock Exchange – US$	**30.34**	58.12
Common share options outstanding (thousands)	**46 127**	48 000
For the six months ended June 30		
Average number outstanding, weighted monthly (thousands)	**936 598**	928 572

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 (2009 – $1,023 million; 2008 – $3,156 million) after adjustment to add back after-tax financing expense (2009 – $663 million; 2008 – income of $49 million) divided by average capital employed (2009 – $14,047 million; 2008 – $10,967 million). Average capital employed is the sum of shareholders' equity and short-term debt plus long-term debt less cash and cash equivalents, at the beginning and end of the year, divided by two, less capitalized costs related to major projects in progress (as applicable). 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. For a detailed reconciliation of ROCE prepared on an annual basis, see page 41 of Suncor's 2008 Annual Report to Shareholders.

(3) If capital employed were to include capitalized costs related to major projects in progress (average capital employed including major projects in progress: 2009 – $20,597 million; 2008 – $15,246 million), the return on capital employed would be as stated on this line.

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

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

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

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

Quarterly Operating Summary

(unaudited)

	Three months ended					Six months ended		Twelve months ended
	June 30 2009	Mar 31 2009	Dec 31 2008	Sept 30 2008	June 30 2008	**June 30 2009**	June 30 2008	Dec 31 2008
OIL SANDS								
Production [1], [a]								
Total production	**301.0**	278.0	243.8	245.6	174.6	**289.0**	211.0	228.0
Firebag	**48.3**	42.4	39.7	40.4	34.7	**45.4**	34.7	37.4
Sales [a]								
Light sweet crude oil	**99.4**	108.8	95.7	48.1	68.2	**104.1**	82.2	77.0
Diesel	**25.3**	22.8	19.1	10.9	21.2	**24.1**	24.6	19.8
Light sour crude oil	**150.5**	102.7	144.2	157.4	91.8	**126.7**	106.3	128.7
Bitumen	**10.5**	9.1	3.1	2.6	0.3	**9.8**	0.2	1.5
Total sales	**285.7**	243.4	262.1	219.0	181.5	**264.7**	213.3	227.0
Average sales price [2], [b]								
Light sweet crude oil	**66.24**	69.26	64.58	121.96	122.12	**67.81**	109.72	97.54
Other (diesel, light sour crude oil and bitumen)	**62.71**	48.85	59.77	114.74	120.52	**56.93**	104.94	95.15
Total	**63.93**	57.97	61.53	116.32	121.12	**61.21**	106.47	95.96
Total *	**63.79**	52.78	61.20	117.14	122.39	**58.15**	107.36	96.33
Cash operating costs and Total operating costs – Total operations [c]								
Cash costs	**29.65**	30.65	35.35	27.80	40.10	**30.15**	31.30	31.45
Natural gas	**1.65**	3.00	4.05	4.30	8.75	**2.30**	6.50	5.25
Imported bitumen	**—**	0.05	1.90	1.90	2.00	**0.05**	1.70	1.80
Cash operating costs [3]	**31.30**	33.70	41.30	34.00	50.85	**32.50**	39.50	38.50
Project start-up costs	**0.35**	0.65	0.30	0.35	0.90	**0.50**	0.55	0.40
Total cash operating costs [4]	**31.65**	34.35	41.60	34.35	51.75	**33.00**	40.05	38.90
Depreciation, depletion and amortization	**7.20**	7.30	7.50	6.70	8.30	**7.25**	6.80	6.95
Total operating costs [5]	**38.85**	41.65	49.10	41.05	60.05	**40.25**	46.85	45.85
Cash operating costs and Total operating costs – In-situ bitumen production only [c]								
Cash costs	**11.15**	10.50	16.55	10.75	10.10	**10.80**	12.35	13.00
Natural gas	**5.25**	7.90	9.65	11.30	14.55	**6.50**	14.40	12.30
Cash operating costs [6]	**16.40**	18.40	26.20	22.05	24.65	**17.30**	26.75	25.30
In-situ (Firebag) start-up costs	**1.50**	3.35	—	0.80	1.65	**2.35**	0.95	0.65
Total cash operating costs [7]	**17.90**	21.75	26.20	22.85	26.30	**19.65**	27.70	25.95
Depreciation, depletion and amortization	**6.00**	7.10	6.55	5.40	6.70	**6.45**	6.70	6.35
Total operating costs [8]	**23.90**	28.85	32.75	28.25	33.00	**26.10**	34.40	32.30
Ending capital employed excluding major projects in progress [i]	**10 008**	10 610	9 352	9 035	7 716			
(for the twelve months ended)								
Return on capital employed [j]	**11.1**	22.9	35.5	46.0	43.6			
Return on capital employed [j]****	**6.5**	13.9	21.8	28.6	27.3			

Quarterly Operating Summary (continued)

(unaudited)

	June 30 2009	Mar 31 2009	Dec 31 2008	Sept 30 2008	June 30 2008	June 30 2009	June 30 2008	Dec 31 2008
	Three months ended					Six months ended		Twelve months ended
NATURAL GAS								
Gross production **								
Natural gas [d]	**192**	200	195	197	205	**196**	207	202
Natural gas liquids and crude oil [a]	**3.2**	3.1	3.1	2.6	3.4	**3.2**	3.4	3.1
Total gross production [e]	**35.1**	36.5	35.6	35.4	37.7	**35.8**	37.9	36.7
Total gross production [f]	**211**	219	213	213	226	**215**	228	220
Average sales price [2]								
Natural gas [g]	**3.56**	5.63	6.90	9.10	9.62	**4.61**	8.45	8.23
Natural gas [g] *	**3.52**	5.61	6.84	9.14	9.68	**4.58**	8.48	8.25
Natural gas liquids and crude oil [b]	**41.39**	39.03	39.31	96.88	86.14	**40.23**	75.39	70.89
Net wells drilled								
Conventional – exploratory ***	**1**	2	2	4	2	**3**	4	10
– development	**2**	5	4	6	6	**7**	13	23
	3	7	6	10	8	**10**	17	33
Ending capital employed [i]	**1 200**	1 195	1 152	1 120	1 226			
(for the twelve months ended)								
Return on capital employed [j]	**(1.7)**	5.0	7.7	10.3	8.3			
REFINING AND MARKETING								
Refined product sales [h]								
Transportation fuels								
Gasoline – retail	**4.6**	4.5	4.6	4.5	4.5	**4.6**	4.6	4.6
– other	**13.0**	11.9	12.1	11.5	11.8	**12.4**	11.3	11.3
Distillate	**10.4**	10.5	10.9	10.6	11.5	**10.5**	11.0	10.8
Total transportation fuel sales	**28.0**	26.9	27.6	26.6	27.8	**27.5**	26.9	26.7
Petrochemicals	**1.0**	1.0	1.0	1.0	0.9	**1.0**	0.8	0.8
Asphalt	**2.1**	2.0	1.5	1.9	1.7	**2.0**	1.8	1.8
Other	**2.8**	1.5	1.4	2.5	2.7	**2.2**	2.3	2.2
Total refined product sales	**33.9**	31.4	31.5	32.0	33.1	**32.7**	31.8	31.5
Crude oil supply and refining								
Processed at refineries [h]	**27.4**	25.5	24.8	25.1	26.0	**26.5**	24.5	24.7
Utilization of refining capacity [j]	**97**	90	98	99	102	**94**	96	97
Ending capital employed excluding major projects in progress [i]	**3 224**	2 985	2 974	3 289	2 534			
(for the twelve months ended)								
Return on capital employed [j]	**3.0**	3.7	1.8	9.3	12.6			
Return on capital employed [j] ****	**3.0**	3.7	1.8	9.0	11.6			

Quarterly Operating Summary (continued)

Non GAAP Financial Measures

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

Definitions

(1) Total operations production	–	Total operations production includes total production from both mining and in-situ operations, as well as volumes processed for Petro-Canada on a fee-for-service basis.
(2) Average sales price	–	This operating statistic is calculated before royalties and net of related transportation costs (including or excluding the impact of realized hedging activities as noted).
(3) Cash operating costs operations – Total operations	–	Include cash costs that are defined as operating, selling and general expenses (excluding inventory changes), accretion expense, taxes other than income taxes 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.
(4) Total cash operating costs – Total operations	–	Include cash operating costs – Total operations as defined above and cash start-up costs. Per barrel amounts are based on total production volumes.
(5) Total operating costs – Total operations	–	Include total cash operating costs – Total operations as defined above and non-cash operating costs. Per barrel amounts are based on total production volumes.
(6) Cash operating costs – In-situ bitumen production	–	Include cash costs that are defined as operating, selling and general expenses (excluding inventory changes), accretion expense and taxes other than income taxes. Per barrel amounts are based on in-situ production volumes only.
(7) 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.
(8) 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.

Explanatory Notes

*	Excludes the impact of realized hedging activities.
**	Currently production is located in the Western Canada Sedimentary Basin.
***	Excludes exploratory wells in progress.
****	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.

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

Metric conversion

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

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