SUNCOR ENERGY

THIRD QUARTER 2008
Report to shareholders for the period ended September 30, 2008

Suncor Energy releases third quarter results

All financial figures are unaudited and in Canadian dollars unless noted otherwise. Certain financial measures referred to in this document are not prescribed by Canadian generally accepted accounting principles (GAAP). For a description of these measures, see “Non-GAAP Financial Measures” in Suncor’s 2008 third 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 third quarter 2008 net earnings of $815 million ($0.87 per common share), compared to $627 million ($0.68 per common share) for the third quarter of 2007. Excluding unrealized foreign exchange impacts on the company’s U.S. dollar denominated long-term debt, and project start-up costs, earnings for the third quarter of 2008 were $971 million ($1.04 per common share), compared to $538 million ($0.58 per common share) in the third quarter of 2007.

The increase in earnings was primarily due to improved price realizations for our oil sands products. This was partially offset by an increase in operating expenses, product purchases and Crown royalties in our oil sands business.

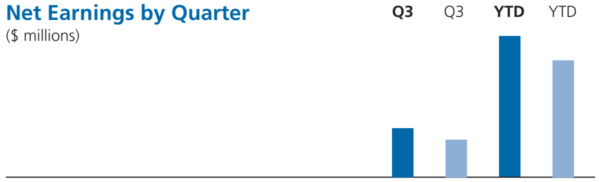
Net earnings for the first nine months of 2008 were $2.352 billion, compared to $1.941 billion for the same period in 2007. Excluding unrealized foreign exchange impacts on the company’s U.S. dollar denominated long-term debt, the impact of income tax rate reductions on opening future income tax liabilities, and project start-up costs, earnings for the first nine months of 2008 were $2.580 billion, compared to $1.712 billion in the same period for 2007.

Cash flow from operations in the third quarter of 2008 was $1.346 billion, compared to $957 million in the same period of 2007. Cash flow from operations for the first nine months of 2008 was $3.912 billion, compared to $2.809 billion in the first nine months of 2007.

The increase in earnings over the first nine months of 2008, and the increase in cash flow from operations for the three and nine month periods ended September 30, 2008, are due primarily to the same factors that impacted third quarter earnings.

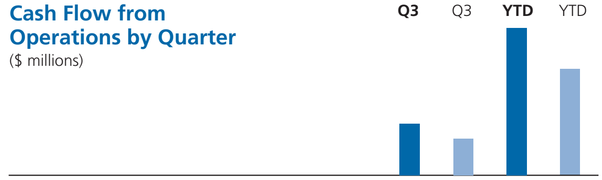
Suncor’s total upstream production averaged 281,000 barrels of oil equivalent (boe) per day in the third quarter of 2008, compared to 274,300 boe per day in the third quarter of 2007. In Suncor’s natural gas business, production was 213 million cubic feet equivalent (mmcfe) per day compared to third quarter 2007 production of 211 mmcfe per day. Oil sands production contributed 245,600 barrels per day (bpd) in the third quarter of 2008 compared to 239,100 bpd in the third quarter of 2007.

Net Earnings by Quarter
($ millions)



	2008 Q3	2007 Q3	2008 YTD	2007 YTD
	815	627	**2,352**	1,941

Cash Flow from Operations by Quarter
($ millions)



	2008 Q3	2007 Q3	2008 YTD	2007 YTD
	1,346	957	**3,912**	2,809

Production
(thousands of barrels of oil equivalent per day)

	2008 Q3	2007 Q3	2008 YTD	2007 YTD
Natural Gas	**35.4**	35.2	**37.1**	35.0
Oil Sands	**245.6**	239.1	**222.6**	229.8
Total	**281.0**	274.3	**259.7**	264.8

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

	2008	2007
Return on average shareholders’ equity	**26.8**	23.3
Return on capital employed	**28.7**	24.0

Oil sands cash operating costs in the third quarter of 2008 averaged $34.00 per barrel, compared to $25.10 per barrel during the third quarter of 2007. The increase in cash operating costs per barrel was due to higher operating expenses and increased natural gas input costs.

Production volumes were lower than planned in the third quarter and as a result, Suncor has adjusted its production outlook to an annual average of 235,000 bpd with a corresponding increase in cash operating costs to a target of $36.50 per barrel.

"We've had a challenging quarter with unplanned maintenance, including issues at our hydrogen facilities that impacted our product mix," said Rick George, president and chief executive officer.

Production volumes in the quarter were impacted by unplanned maintenance activities in our upgrading and extraction assets. In addition, an unplanned shutdown of facilities that supply hydrogen reduced production of higher-value sweet (low sulphur) synthetic crude oil and diesel. Repairs to the facilities are complete and production of sweet products is increasing.

"With these issues behind us, we continue to target production of approximately 300,000 barrels per day by the end of the year as we work to realize the full value of our expanded oil sands production facilities," said George.

Commissioning of Suncor's $2.3 billion expansion to one of two oil sands upgraders is nearing completion and production volumes are expected to continue ramping up in 2009 toward design capacity of 350,000 bpd.

Bitumen feedstock from Suncor's Firebag in-situ operations is also expected to increase following the lifting in July of a production cap imposed by provincial regulators. Wells that had been shut in have begun steaming and small amounts of incremental production are expected to come on line in the fourth quarter of 2008.

Operations and growth update

On October 23, Suncor announced an update to the schedule of its $20.6 billion Voyageur growth strategy, including reporting plans for 2009 capital spending of $6 billion.

"In light of current financial market conditions, we've modified our capital plans for 2009, reducing targeted spending by more than a third," said George. "Our aim is to ensure we are living within our means during a time of market uncertainty, while also making the strategic spending decisions that will allow us to continue on our growth path."

The company's growth outlook maintains spending and construction timelines for the third and fourth stages of Firebag in-situ operations. Completion of Firebag Stages 3 and 4 (in 2009 and 2010, respectively) is expected to provide increases in bitumen production and future cash flow.

In the near-term, Suncor expects to scale down spending and the pace of construction on the company's planned Voyageur upgrader, delaying targeted completion by approximately one year to the end of 2012. Stages 5 and 6 of Firebag in-situ operations are expected to proceed but, as they are at relatively early phases of development, spending and scheduling plans remain flexible to respond to market conditions.

Of the total Voyageur capital budget of $20.6 billion, Suncor had spent approximately $5.3 billion at the end of the third quarter.

"We remain committed to an integrated expansion strategy and targeted oil sands production of 550,000 barrels per day," said George. "However, we've always had options available to us in terms of how the expansion is rolled out – and we believe in the current economic environment it's prudent to exercise that flexibility."

The company's 2009 capital spending plan is expected to be financed through undrawn credit facilities and cash flow from operations. As Suncor invests for future growth, prudent debt management remains a priority. Net debt levels increased to $5.3 billion in the third quarter of 2008 from $3.2 billion at year-end 2007.

Outlook

Suncor's outlook provides management's targets for 2008 in certain key areas of the company's business. Users of this information are cautioned that actual results can vary from the targets disclosed.

	Nine Month Actuals Ended September 30, 2008	2008 Full Year Outlook
Oil Sands		
Production (bpd)(1)	**222 600**	235 000
Diesel	**9%**	9%
Sweet	**33%**	34%
Sour	**57%**	56%
Bitumen	**1%**	1%
Realization on crude sales basket(1)	**WTI @ Cushing less Cdn$3.37 per barrel**	WTI @ Cushing less Cdn$3.50 to Cdn$4.50 per barrel
Cash operating costs(1)(2)	**$37.45 per barrel**	$36.50 per barrel
Natural Gas		
Production(1)(3) (mmcf equivalent per day)	**223**	220
Natural gas	**91%**	91%
Liquids	**9%**	9%

(1) Based on third quarter results and expectations for the fourth quarter, the outlook for oil sands production, cash operating costs, realization on crude sales basket and natural gas production has been adjusted. The June 30 oil sands production outlook was 240,000 to 250,000 bpd (diesel 12%, sweet 38%, sour 50%, and bitumen 0%) with a corresponding cash operating cost range of $35.00 to $36.00 per barrel. The June 30 realization on crude sales basket was WTI @ Cushing less Cdn$2.50 to Cdn$3.50. The June 30 natural gas production outlook was 210 to 220 mmcf equivalent per day.

(2) Cash operating cost estimates are based on the following assumptions: production volumes and sales mix as described in the table above and a natural gas price of $8.00 per gigajoule at AECO. Based on natural gas prices in the first nine months of 2008 and expectations for the fourth quarter, the natural gas price assumption has been adjusted. The June 30 natural gas price assumption was $6.70 per gigajoule at AECO. This estimate also includes costs incurred for third-party bitumen purchases. Cash operating costs per barrel are 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.

(3) 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.

Assumptions used to develop our outlook are based on year-to-date performance and management's best estimates for the remainder of the year.

Factors that could potentially impact Suncor's operations and financial performance in 2008 include:

- Bitumen supply. Ore grade quality, unplanned mine equipment and extraction plant maintenance, tailings storage and regulatory restrictions could impact 2008 production targets. Production could also be impacted by the availability of third-party bitumen.
- Planned maintenance to portions of Upgrader 2. Although this maintenance is reflected in operational targets for the year, production estimates could be impacted if unplanned work is identified, or the schedule is impacted by labour or material supply issues.
- Crude oil hedges. Suncor has hedging agreements for 10,000 bpd in 2008. These costless collar hedges have an average floor of US$59.85 per barrel with an average ceiling of US$101.06 per barrel.

The preceding paragraphs and table contain forward-looking information and users of this information are cautioned that actual results may differ. For additional information on risks, uncertainties and other factors that could cause actual results to differ, please refer to our 2008 Third Quarter Management's Discussion and Analysis, 2007 Annual Report and 2007 Annual Information Form/Form 40-F on file with securities regulators.

Management's Discussion and Analysis

October 28, 2008

This Management's Discussion and Analysis (MD&A) contains forward-looking statements. These statements are based on certain estimates and assumptions and involve risks and uncertainties. Users of forward-looking information are cautioned that actual results may differ materially from those expressed or implied. Forward-looking information and the factors or assumptions used to develop such information are identified throughout this MD&A and under the Legal Notice on page 18. For information on risks, uncertainties and other factors that could cause actual results to differ, see page 18.

This MD&A should be read in conjunction with our September 30, 2008 unaudited interim consolidated financial statements and notes. Readers should also refer to our MD&A on pages 10 to 48 of our 2007 Annual Report and to our Annual Information Form (AIF) dated February 27, 2008. 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 46 of our 2007 Annual Report, and page 16 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 ventures, 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.

In order to provide shareholders with full disclosure relating to potential future capital expenditures, we have provided cost estimates for significant capital projects that, in some cases, are still in the early stages of development. These costs are preliminary estimates only. The actual amounts are expected to differ and these differences may be material. For a further discussion of our significant capital projects, see the Significant Capital Project Update on page 12.

Selected Financial Information

Industry Indicators (average for the period)	Three months ended September 30 **2008**	2007	Nine months ended September 30 **2008**	2007
West Texas Intermediate (WTI) crude oil US$/barrel at Cushing	**118.00**	75.40	**113.30**	66.20
Canadian 0.3% par crude oil Cdn$/barrel at Edmonton	**123.00**	80.25	**115.90**	73.10
Light/heavy crude oil differential US$/barrel WTI at Cushing less Western Canadian Select at Hardisty	**18.05**	22.85	**20.40**	19.60
Natural Gas US$/mcf at Henry Hub	**10.10**	6.15	**9.65**	6.90
Natural Gas (Alberta spot) Cdn$/mcf at AECO	**9.25**	5.60	**8.55**	6.80
New York Harbour 3-2-1 crack (1) US$/barrel	**10.65**	11.95	**10.30**	15.40
Exchange rate: US$/Cdn$	**0.96**	0.96	**0.98**	0.91

(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 the New York Harbour distillate margin and dividing by three.

Outstanding Share Data (1) (as at September 30, 2008)	
Common shares	934 916 409
Common share options – total	46 829 297
Common share options – exercisable	25 646 718

(1) On May 14, 2008, the Company implemented a two-for-one stock split of its issued and outstanding common shares.

Summary of Quarterly Results

	Three months ended							
($ millions, except per share)	**Sept 30 2008**	June 30 2008	Mar 31 2008	Dec 31 2007	Sept 30 2007	June 30 2007	Mar 31 2007	Dec 31 2006
Revenues	**8 946**	7 959	5 988	5 185	4 802	4 525	4 053	3 936
Net earnings	**815**	829	708	1 042	627	738	576	334
Net earnings per common share								
Basic	**0.87**	0.89	0.76	1.13	0.68	0.80	0.63	0.36
Diluted	**0.86**	0.87	0.75	1.10	0.66	0.78	0.61	0.35

Analysis of Consolidated Statements of Earnings and Cash Flows

Net earnings for the third quarter of 2008 were $815 million, compared to $627 million for the third quarter of 2007. Excluding unrealized foreign exchange impacts on the company's U.S. dollar denominated long-term debt, and project start-up costs, earnings for the third quarter of 2008 were $971 million, compared to $538 million in the third quarter of 2007.

The increase in earnings was primarily due to improved price realizations for our oil sands products. This was partially offset by an increase in operating expenses, product purchases and Crown royalties in our oil sands business.

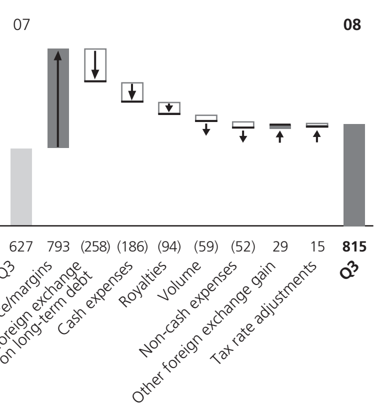
Net earnings for the first nine months of 2008 were $2.352 billion, compared to $1.941 billion for the same period in 2007. Excluding unrealized foreign exchange impacts on the company's U.S. dollar denominated long-term debt, the impact of income tax rate reductions on opening future income tax liabilities, and project start-up costs, earnings for the first nine months of 2008 were $2.580 billion, compared to $1.712 billion in the same period for 2007.

Cash flow from operations in the third quarter of 2008 was $1.346 billion, compared to $957 million in the same period of 2007. Cash flow from operations for the first nine months of 2008 was $3.912 billion, compared to $2.809 billion in the first nine months of 2007.

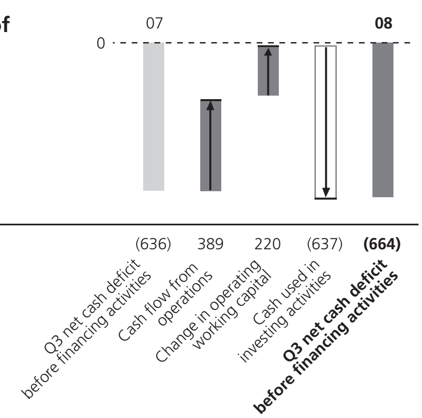
The increase in earnings over the first nine months of 2008, and the increase in cash flow from operations for the three and nine month periods ended September 30, 2008, are due primarily to the same factors that impacted third quarter earnings.

Our effective tax rate for the first nine months of 2008 was 29%, compared to 28% in the first nine months of 2007. During the nine months ended September 30, 2008 we recorded $406 million in current income tax expense, compared to $314 million in the nine months ended September 30, 2007 (see page 10 for discussion of cash income taxes).

Bridge Analysis of Consolidated Net Earnings
($ millions)



Bridge Analysis of Consolidated Net Cash Flow
($ millions)



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.

($ millions, after-tax)	Three months ended September 30 2008	Three months ended September 30 2007	Nine months ended September 30 2008	Nine months ended September 30 2007
Earnings before the following items:	**971**	538	**2 580**	1 712
Unrealized foreign exchange gain (loss) on U.S. dollar denominated long-term debt	**(150)**	108	**(207)**	199
Impact of income tax rate reductions on opening future income tax liabilities	**—**	—	**—**	67
Project start-up costs	**(6)**	(19)	**(21)**	(37)
Net earnings as reported	**815**	627	**2 352**	1 941

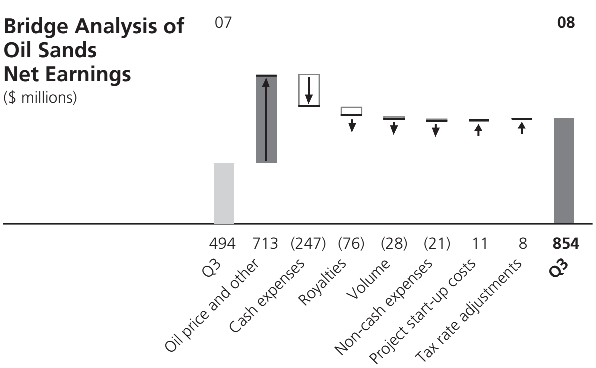
Analysis of Segmented Earnings and Cash Flows

Oil Sands

Oil sands recorded 2008 third quarter net earnings of $854 million, compared with $494 million in the third quarter of 2007. Excluding the impact of project start-up costs, earnings for the third quarter of 2008 were $860 million, compared to $511 million in the third quarter of 2007.

Earnings increased primarily as a result of strong price realizations due to higher benchmark WTI crude oil prices. Earnings were negatively impacted by an increase in operating expenses, product purchases and Crown royalties, in addition to decreased production of higher-value sweet crude oil products resulting from an unplanned shutdown of facilities that supply hydrogen used to remove sulphur from synthetic crude oil and diesel fuel.

Bridge Analysis of Oil Sands Net Earnings
($ millions)



Purchases of crude oil and products were $175 million in the third quarter of 2008, compared to $68 million in the third quarter of 2007. The increase was primarily a result of purchases of product to facilitate transportation of sour crude shipments during the quarter, in addition to third-party bitumen purchases due to additional upgrading capacity.

Operating expenses were $799 million in the third quarter of 2008, compared to $604 million in the third quarter of 2007. The increase in operating expenses in the third quarter of 2008 was primarily due to higher maintenance expenses aimed at improving reliability, increased energy input costs, higher contract mining costs and increased employee costs resulting from higher overall salaries and an increased number of employees.

Alberta Crown royalty expense was $249 million in the third quarter of 2008, compared to $145 million in the third quarter of 2007. The increase was due mainly to higher revenues resulting from continued strong WTI crude pricing. This increase was partially offset by the impact of both higher operating expenses and higher capital expenditures eligible for deduction under Crown royalty formulas. For a further discussion of Crown royalties, see page 7.

Cash flow from operations was $1.109 billion in the third quarter of 2008, compared to $829 million in the third quarter of 2007. The increase was primarily due to the same factors that impacted oil sands earnings.

Net earnings for the first nine months of 2008 were $2.300 billion, compared to $1.438 billion in the first nine months of 2007. Cash flow from operations for the first nine months of 2008 increased to $3.193 billion from $2.086 billion in the first nine months of 2007. The year-to-date increases in net earnings and cash flow from operations were due primarily to the same factors that impacted third quarter oil sands results.

Oil sands production averaged 245,600 barrels per day (bpd) in the third quarter of 2008 compared to production of 239,100 bpd during the third quarter 2007. Unplanned maintenance in our upgrading and extraction assets and wet weather in August that impacted mine production restricted production volumes in the third quarter of 2008. Production volumes in the third quarter of 2007 were impacted by a planned shutdown. Based on third quarter results and expectations for the fourth quarter, the oil sands production outlook has been reduced to an annual average of 235,000 bpd.

Sales volumes during the third quarter of 2008 averaged 219,000 bpd, compared with 223,900 bpd during the third quarter of 2007. The proportion of higher value diesel fuel and sweet crude products decreased to 27% of total sales volumes in the third quarter of 2008, compared to 55% in the third quarter of 2007, primarily due to the unplanned hydrogen facilities shutdown.

The average price realization for oil sands crude products increased to $116.32 per barrel in the third quarter of 2008, compared to $76.97 per barrel in the third quarter of 2007, as a result of a 56% increase in benchmark WTI crude oil prices, partially offset by a decreased premium to WTI for sweet crude blends and an increased discount to WTI for sour crude blends.

During the third quarter of 2008, cash operating costs averaged $34.00 per barrel, compared to $25.10 per barrel during the third quarter of 2007. The increase in cash operating costs per barrel was primarily due to higher operating expenses and increased natural gas input costs. Based on third quarter results and expectations for the fourth quarter, the oil sands cash operating cost outlook has been increased to an annual average of $36.50 per barrel. Refer to page 16 for further details on cash operating costs as a non-GAAP financial measure, including the calculation and reconciliation to GAAP measures.

Oil Sands Operations and Growth Update

Commissioning of Suncor's $2.3 billion expansion to one of two oil sands upgraders is nearing completion and production volumes are expected to continue ramping up toward a target of approximately 300,000 bpd by the end of the year. With additional bitumen feedstock planned to come on line from Firebag, we expect upgrading operations to begin ramping up in 2009 toward design capacity of 350,000 bpd.

Production from Suncor's Firebag in-situ operations had been limited by provincial regulators to 42,000 bpd due to sulphur emissions that exceeded regulatory limits in 2007. With the lifting of the production cap in July, Suncor began steaming new wells in the third quarter and expects small amounts of incremental production to come on line in the fourth quarter of 2008.

On October 23, we announced an update to the schedule of Suncor's $20.6 billion Voyageur growth strategy, including reporting plans for 2009 capital spending of $6 billion.

We believe it is prudent to reduce capital spending from previously anticipated levels during a time of financial market uncertainty that has impacted the cost of issuing new debt. At currently planned spending, we expect to finance our 2009 capital program through existing undrawn credit facilities and cash flow from operations.

The modified capital plan and related growth outlook maintains spending and construction timelines for the third and fourth stages of Firebag in-situ operations. Completion of Firebag Stages 3 and 4 (in 2009 and 2010, respectively) is expected to provide increases in bitumen production and future cash flow.

We had previously expected to complete construction of a third upgrader, the centerpiece of the Voyageur expansion, in late 2011 with oil sands production capacity of 550,000 bpd in place in 2012. Suncor has delayed these plans and is scaling down spending and the pace of construction on the planned upgrader, extending targeted completion by approximately one year to the end of 2012. Stages 5 and 6 of Firebag in-situ operations are expected to proceed but, as they are at relatively early phases of development, spending and scheduling plans remain flexible to respond to market conditions.

Of the total Voyageur capital budget of $20.6 billion, Suncor had spent approximately $5.3 billion at the end of the third quarter.

For an update on our significant growth projects currently in progress see page 12. The information provided in the growth update contains forward-looking statements and users of this information are cautioned that actual results may differ. For additional information on risks, uncertainties and other factors that could cause actual results to differ, please see page 18.

Oil Sands Crown Royalties

For a description of the Alberta Crown royalty regimes in effect for our oil sands operations, see page 19 of our 2007 Annual Report and note 11 of our third quarter 2008 financial statements.

In the third quarter of 2008, we recorded a pretax royalty estimate of $249 million, compared to $145 million for the third quarter of 2007. In 2008, the estimation process for calculating the quarterly royalty provision was changed from being based on an annual royalty estimate to being based on the actual eligible revenues and costs recorded in the period. If the annualized approach was used for 2008, pretax royalties would have been $86 million higher for the first nine months of 2008.

The following table sets forth our estimates of royalties in the years 2008 through 2012, and certain assumptions on which we have based our estimates.

Oil Sands Mining and In-Situ Royalties

WTI Price/bbl (US$)	**80**	**100**	**130**
Natural gas (Alberta spot) Cdn$/mcf at AECO	7.50	8.00	9.50
Light/heavy oil differential of WTI at Cushing less Maya at the U.S. Gulf Coast US$	14.00	18.00	23.00
Differential of Maya at the U.S. Gulf Coast less Western Canadian Select at Hardisty, Alberta US$	7.00	7.00	7.00
US$/Cdn$ exchange rate	1.00	1.00	1.05
Crown Royalty Expense (based on percentage of total oil sands revenue) %			
2008 – Mining synthetic crude oil, in-situ bitumen (25% and 1% min)	8-9	9-10	10-11
2009 – Bitumen (mining old rates – 25% and 1% min; in-situ new rates)	6-8	9-11	11-13
2010 to 2012 – Bitumen (new rates – cap 30% for mining)	6-8	9-11	12-14

The previous table contains forward-looking information and users of this information are cautioned that actual Crown royalty expense may vary from the ranges disclosed in the table. The royalty ranges disclosed in the table were developed using the following assumptions: current agreements with the government of Alberta (assuming the government enacts their proposed framework), royalty rates proposed by the government of Alberta, current forecasts of production, capital and operating costs, and the 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) Pursuant to the new royalty framework, the government proposed on June 30, 2008 a generic "bitumen valuation methodology" for determining the gross revenues less related transportation costs related to bitumen. The proposal uses the Hardisty, Alberta pricing of Western Canadian Select (WCS), a widely traded blend of Alberta bitumen, diluents and conventional heavy oil, as a benchmark. The proposed pricing formula is adjusted for transportation to Hardisty, the value of diluent in the WCS blend and the constituent bitumen quality. The proposal also provides for a floor price based on Maya at the U.S. Gulf Coast if there are unusual market fluctuations affecting WCS relative to the North American market. Following a consultation period with industry, the government expects to implement the new bitumen valuation methodology January 1, 2009, with further refinements for bitumen quality determination expected January 1, 2010. The estimated impact of quality adjustments and other assumptions have been incorporated into the above table. Those assumptions and the final determination of the bitumen valuation methodology may have a material impact on royalties payable to the Crown. For our mining operations, the proposed bitumen methodology is consistent with Suncor's January 2008 Crown Agreement which places certain limitations on the bitumen valuation methodology;

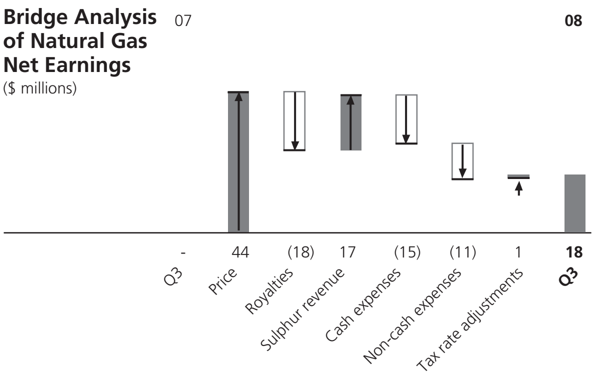
(ii) The government announced in April 2008 it will implement recommendations to enhance how the performance of the royalty regime is measured and reported. They are also in the process of reviewing technical policy details and business rules that are being changed to align with the new royalty framework announced in October 2007. Steps taken by the government may affect the calculation of royalties; and

(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 to the generic royalty regime 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.

Natural Gas

Our natural gas business recorded net earnings of $18 million in the third quarter of 2008, compared with nil during the third quarter of 2007. Net earnings increased primarily as a result of higher revenues driven by stronger price realizations, including higher sulphur prices. These factors were partially offset by higher royalties and dry hole costs, and increased depreciation, depletion and amortization (DD&A) expense resulting from increased production from areas with larger capital bases.

Bridge Analysis of Natural Gas Net Earnings
($ millions)



Cash flow from operations for the third quarter of 2008 was $103 million, compared to $47 million in the third quarter of 2007. The increase is primarily due to the same factors affecting net earnings, excluding the impact of DD&A and dry hole costs.

Net earnings in the first nine months of 2008 were $89 million, compared to nil in the first nine months of 2007. Net earnings increased primarily as a result of higher revenues driven by stronger price realizations, higher sulphur prices and increased production, in addition to a gain on the sale of non-core assets. These factors were partially offset by higher royalties and increased DD&A expense. Cash flow from operations for the first nine months of the year was $304 million, compared to $181 million reported in the same period in 2007. The increase is primarily due to the same factors affecting net earnings, excluding the impact of DD&A and the gain on the sale of non-core assets.

Natural gas and liquids production in the third quarter of 2008 was 213 million cubic feet equivalent (mmcfe) per day, compared to 211 mmcfe per day in the third quarter of 2007. The increased production compared to the prior year was primarily due to the addition of new wells. Our 2008 planned production is expected to offset Suncor's estimated purchases of natural gas for internal consumption at our oil sands operations.

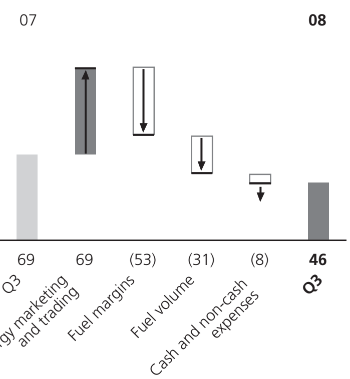
Realized natural gas prices in the third quarter of 2008 were $9.10 per thousand cubic feet (mcf), compared to $5.39 per mcf in the third quarter of 2007, reflecting higher benchmark prices.

Refining and Marketing

Refining and marketing recorded 2008 third quarter net earnings of $46 million, compared to net earnings of $69 million in the third quarter of 2007. The decrease in net earnings primarily resulted from reduced margins on gasoline, asphalt and other heavy products as well as significantly lower refined product demand driven by the high prices of finished products, particularly gasoline. These factors were partially offset by gains from energy marketing and trading activities, which increased to $99 million in the third quarter of 2008, from $1 million in the third quarter of 2007. This increase was primarily due to gains on crude oil financial contracts.

As a result of adopting a required FIFO (first-in-first-out) valuation accounting policy for inventory, net earnings were $134 million lower than they would have been under the previous LIFO (last-in-first-out) accounting policy. Under FIFO accounting, earnings are impacted by the change in value of crude feedstock inventories. In the third quarter of 2007, FIFO accounting resulted in a $29 million positive impact. For further details of this change in accounting policy, see page 15.

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



Cash flow from operations was $85 million in the third quarter of 2008, compared to $126 million in the third quarter of 2007. Cash flow from operations decreased primarily due to the same factors affecting net earnings, excluding the impact of unrealized gains from energy marketing and trading activities.

During the third quarter of 2008, refinery crude oil utilization was 99%, compared to 102% in the third quarter of 2007. This lower rate was primarily due to unplanned maintenance at our Commerce City, Colorado refinery. In addition, our Sarnia refinery completed a planned maintenance shut-down that began on September 2, 2008 and lasted until October 11, 2008. This turnaround was completed on schedule and on budget, and did not have a significant impact on the quarter over quarter utilization comparison as Sarnia completed a similar scope turnaround during the third quarter of 2007.

Our refining and marketing business recorded net earnings of $232 million for the first nine months of 2008, compared to $413 million during the first nine months of 2007. Cash flow from operations for the first nine months of 2008 was $485 million, compared to $648 million in the first nine months of 2007. The year-to-date decreases in net earnings and cash flow from operations were due to the same factors that impacted third quarter results.

Corporate and Eliminations

After-tax net corporate expense was $103 million in the third quarter of 2008, compared to earnings of $64 million in the third quarter of 2007. Excluding the impact of group elimination entries, after-tax net corporate expense was $115 million in the third quarter of 2008 (earnings of $64 million in the third quarter of 2007). Net expense increased mainly due to unrealized foreign exchange losses on our U.S dollar denominated long-term debt. After-tax unrealized foreign exchange losses on U.S. dollar denominated long-term debt were $150 million in the third quarter of 2008, compared to gains of $108 million in the third quarter of 2007. Group elimination entries increased to $12 million in the third quarter of 2008, from nil in the third quarter of 2007, primarily as a result of profit elimination on inventory sold from oil sands to refining and marketing.

Breakdown of Net Corporate Expense

Three months ended September 30 ($ millions)	**2008**	2007
Corporate (expense) earnings	**(115)**	64
Group eliminations	**12**	—
Total	**(103)**	64

Cash flow from operations was $49 million in the third quarter of 2008, compared to cash used in operations of $45 million in the third quarter of 2007. This was primarily due to a foreign exchange gain on operational activities in the third quarter of 2008, compared to a loss in the third quarter of 2007.

Corporate net expense was $269 million in the first nine months of 2008, compared to net earnings of $90 million in the same period of 2007. Net expense increased mainly due to unrealized foreign exchange losses on our U.S. dollar denominated long-term debt. After-tax unrealized foreign exchange losses on U.S. dollar denominated long-term debt were $207 million in the nine months ended September 30, 2008, compared to gains of $199 million in the first nine months of 2007. Cash used in operations was $70 million in the first nine months of 2008, compared to $106 million in the first nine months of 2007.

Cash Income Taxes

We estimate we will have cash income taxes of 30% to 50% of our effective tax rate during 2008. Thereafter, we anticipate our cash income tax position may fluctuate to a maximum of approximately 100% of our effective tax rate by 2015. 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, the commodity prices and exchange rates described in the table "Oil Sands Mining and In-Situ Royalties" on page 8 and effective income tax rates within 2% of the statutory income tax rates, 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 from our outlook.

Analysis of Financial Condition and Liquidity

Excluding cash and cash equivalents, short-term debt and future income taxes, Suncor had an operating working capital deficiency of $111 million at the end of the third quarter of 2008, compared to a deficiency of $430 million at the end of the third quarter of 2007, due primarily to an increase in inventory values, reflecting higher commodity prices.

During the first nine months of 2008, net debt increased to $5.260 billion from $3.248 billion at December 31, 2007, primarily due to increased capital spending to fund our growth strategies.

During 2008, the company's $2 billion committed syndicated credit facility was increased to $3.75 billion and its term was extended to 2013, while our $410 million committed bilateral credit facility was reduced to $370 million and extended to 2009.

In May 2008, the company issued 5.80% Medium Term Notes with a principal amount of $700 million under an outstanding $2 billion debt shelf prospectus. Interest on the notes is paid semi-annually, and the notes mature on May 22, 2018. The net proceeds received were added to our general funds to repay outstanding commercial paper, which originally funded our working capital needs, sustaining capital expenditures and growth capital expenditures.

In June 2008, the company issued 6.10% Notes with a principal amount of US$1.25 billion and 6.85% Notes with a principal amount of US$750 million under an amended US$3.65 billion debt shelf prospectus. Interest on the notes is paid semi-annually, and the notes mature on June 1, 2018, and June 1, 2039, respectively. The net proceeds received were added to our general funds, which are used for our working capital needs, sustaining capital expenditures, growth capital expenditures and to repay outstanding commercial paper borrowings.

At September 30, 2008, our undrawn credit facilities were approximately $3.5 billion and we had cash and cash equivalents of approximately $1.3 billion. Outstanding debt shelf prospectuses filed in 2007 enable the company to issue debt in Canada and the United States. We believe we have the capital resources from our undrawn credit facilities and cash flow from operations to meet our current working capital requirements and fund the remainder of our $7.5 billion 2008 capital program and recently announced $6 billion 2009 capital program. For additional information on risks, uncertainties and other factors affecting our ability to fund our capital program, see page 18.

Significant Capital Project Update

A summary of the progress on our significant projects under construction to support both our growth and sustaining needs is provided below. All projects listed below have received board of directors approval.

Project	Plan	Cost estimate $ millions (1)	Estimate % Accuracy (1)	Spent to date	% complete Engineering	% complete Construction (2)	Target completion date
Coker Unit	Expected to increase production capacity by 90,000 bpd	2 100	+13/−7	2 285	100	100	Complete
Naphtha Unit	Increases sweet product mix	650	+10/−10	575	99	45	2009
Steepbank Extraction Plant	New location and new technologies aimed at improving operational performance	850	+10/−10	585	100	60	2009
Firebag Sulphur Plant	Support emission abatement plan at Firebag; capacity to support Stages 1-6	340	+10/−10	220	85	40	2009
North Steepbank Mine Expansion	Expected to supply ore to generate about 180,000 bpd of bitumen	400	+10/−10	110	50	30	2010 (3)
Voyageur Strategy: Firebag (4)	Expansion of Firebag 3-6 is expected to generate about 270,000 bpd of bitumen	9 000	+18/−13	2 770 (5)			
	– Stage 3				95	40	2009
	– Stage 4 (6)(7)				60	—	2010
	– Stage 5 (6)(7)				10	—	2012 (8)
	– Stage 6 (6)(7)				10	—	2012 (8)
Voyageur Strategy: Upgrader 3 (9)	Expected to increase production capacity by 200,000 bpd	11 600	+12/−8	2 570 (5)	70	10	2012 (8)

(1) Excludes commissioning and start-up costs. Cost estimates and estimate accuracy reflect budgets approved by Suncor's Board of Directors.
(2) Excludes commissioning and start-up.
(3) As a result of an update in operating plans, management has adjusted its target completion date to 2010 from 2009. Production from the mine expansion is targeted to begin in 2012.
(4) Ramp-up to full capacity of each stage can take up to eighteen months from completion of construction.
(5) Spending to date includes procurement of major project components. For Firebag Stage 3, procurement at September 30, 2008 was 90% complete; for Stage 4, 81% complete; for Stage 5, 15% complete; and for Stage 6, 48%. For Upgrader 3, procurement was 70% complete.
(6) Pending regulatory approval.
(7) Construction of shared and common services is included in Stage 3 construction.
(8) As a result of changes to the timing of capital spending plans, management has adjusted its target completion date to 2012 from 2011.
(9) Construction completion targeted in 2012 with ramp-up to full capacity during 2013.

The previous table contains forward-looking information and users of this information are cautioned that the actual timing, amount of the final capital expenditures and expected results for each of these projects may vary from the plans disclosed in the table. 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 this table are contained in our 2007 Annual Report, pages 21 to 26. For additional information on risks, uncertainties and other factors that could cause actual results to differ, please see page 18.

The material factors used to develop the target completion dates and cost estimates are: capital spending plans, the current status of procurement, design and engineering phases of the project; updates from third parties on delivery of services and goods 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

On January 1, 2008, Suncor adopted the Canadian Institute of Chartered Accountants (CICA) Handbook sections 3862 "Financial Instruments – Disclosures" and 3863 "Financial Instruments – Presentation", which enhance existing disclosures for financial instruments. In particular, section 3862 focuses on the identification of risk exposures and our approach to management of these risks. These new disclosures have been incorporated in the following discussion and in the notes to our unaudited financial statements.

We periodically enter into derivative contracts to hedge against the potential adverse impact of market price volatility due to changes in the underlying indices. We also use physical and financial energy contracts to earn trading and marketing revenues.

We have estimated fair values of 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.

Commodity and Treasury Hedging Activities

To provide an element of stability to future earnings and cash flow, we have approval from the board of directors to fix a price or range of prices for up to approximately 30% of our total planned production of crude oil for specified periods of time. The company has hedged a portion of its forecasted U.S. dollar denominated sales subject to U.S. dollar West Texas Intermediate (WTI) commodity price risk. As of September 30, 2008, costless collar crude oil hedges totaling 10,000 bpd of production were outstanding for the remainder of 2008. Prices for these barrels are fixed within a range from an average of US$59.85/bbl up to an average of US$101.06/bbl. In addition to these hedges, we have crude oil puts for 55,000 bpd of production for 2009 and 2010 that provide us with a floor price of US$60.00/bbl.

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 result 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 in the Consolidated Statements of Earnings and Comprehensive Income.

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. In addition to our interest rate swap contracts, we also manage variability in market interest rates and foreign exchange rates during periods of debt issuance through the use of interest rate locks and foreign exchange forward contracts.

The earnings impact associated with changes in the fair values of our commodity and treasury hedging derivative financial instruments in the third quarter of 2008 was a pretax gain of $74 million (2007 – pretax gain of $2 million). The earnings impact in the first nine months of 2008 was a pretax loss of $14 million (2007 – pretax loss of $9 million).

Energy Marketing and Trading Activities

In addition to derivative contracts used for hedging activities, Suncor uses physical and financial energy derivatives to earn trading and marketing revenues. These energy contracts are comprised of crude oil, natural gas, heating oil and gasoline derivative contracts. The results of these trading activities are reported as revenue and as energy marketing and trading expenses in the Consolidated Statements of Earnings and Comprehensive Income. The net pretax gains associated with our energy marketing and trading activities in the third quarter of 2008 were $99 million (2007 – pretax earnings of $1 million). The net pretax earnings in the first nine months of 2008 were $116 million (2007 – pretax earnings of $26 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)	**September 30 2008**	December 31 2007
Derivative financial instruments accounted for as hedges		
Assets	**17**	20
Liabilities	**(6)**	(11)
Derivative financial instruments not accounted for as hedges		
Assets	**148**	18
Liabilities	**(20)**	(21)
Net derivative financial instruments	**139**	6

For further details on our derivative financial instruments, see note 3 to the unaudited interim consolidated financial statements on page 28.

Environmental Regulation and Risk

Production from Suncor's Firebag in-situ operations had been limited by regulators to 42,000 bpd due to sulphur emissions that exceeded regulatory limits in 2007. With the lifting of the production cap during the third quarter, Suncor began steaming new wells, with small amounts of incremental production expected to come on line in the fourth quarter of 2008.

In April 2007, the Canadian federal government introduced the Clean Air regulatory framework, which is expected to regulate both greenhouse gas (GHG) emissions and air pollutants from industrial emitters. Further details on the GHG framework were released in March 2008. Suncor has been engaged in the ongoing consultations on this framework. In support of developing regulation, Suncor submitted production, operations and emissions information for designated facilities to the federal government in May. Draft GHG regulations are expected in fall 2008, with final regulations in fall 2009 and the provisions coming into force on January 1, 2010. The financial impact of this proposed legislation will be dependent on the details of Clean Air Act regulations.

On June 26, 2008, the Energy Resources Conservation Board (ERCB) released a draft directive, Tailings Performance Criteria and Requirements for Oil Sands Mining Schemes, for industry review and comment until September 15, 2008. The directive proposes to establish performance criteria for consolidated tailings (CT) operations, a requirement for specific approval and monitoring of CT ponds, a requirement for reporting tailings plans, and changes to the ERCB annual mine plan requirements and approval process to regulate tailings operations. We do not expect any significant impact resulting from the directive as currently drafted.

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 such as carbon capture and sequestration.

Control Environment

Based on their evaluation as of September 30, 2008, our chief executive officer and chief financial officer concluded that our disclosure controls and procedures (as defined in Rules 13(a) – 15(e) and 15(d) – 15(e) under the United States Securities Exchange Act of 1934 (the Exchange Act)) are effective to ensure that information required to be disclosed in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms. In addition, as of September 30, 2008, there were no changes in our internal control over financial reporting that occurred during the three month period ended September 30, 2008 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.

Change in Accounting Policies

(a) Inventories

On January 1, 2008 Suncor was required to retroactively adopt CICA Handbook section 3031 "Inventories". Under the new standard, the use of a LIFO (last-in-first-out) based valuation approach for inventory has been eliminated.

The standard also requires any impairment to net realizable value of inventory to be written down at each reporting period, with subsequent reversals when applicable. Suncor transitioned to a FIFO (first-in-first-out) based valuation approach for inventory effective January 1, 2008. The impact of adopting this standard is as follows:

Change in Consolidated Balance Sheets

($ millions, increase/(decrease))	**September 30 2008**	December 31 2007
Inventories	**473**	404
Total Assets	**473**	404
Accounts payable and accured liabilities	**(25)**	—
Future income taxes	**157**	121
Retained earnings	**341**	283
Total liabilities and shareholders' equity	**473**	404

Change in Consolidated Statements of Earnings and Comprehensive Income

	Three months ended September 30		Nine months ended September 30	
($ millions, increase/(decrease))	**2008**	2007	**2008**	2007
Purchase of crude oil and products	**191**	(19)	**(144)**	(94)
Operating, selling and general	**186**	89	**50**	(14)
Future income taxes	**(110)**	(20)	**36**	36
Net earnings	**(267)**	(50)	**58**	72
Per common share – basic (dollars)	**(0.28)**	(0.05)	**0.06**	0.08
Per common share – diluted (dollars)	**(0.28)**	(0.05)	**0.06**	0.08

Segmented Net Earnings Impact

	Three months ended September 30		Nine months ended September 30	
($ millions, increase/(decrease))	**2008**	2007	**2008**	2007
Net earnings				
Oil sands	**(135)**	(62)	**(39)**	10
Refining and marketing	**(134)**	29	**125**	68
Corporate and eliminations	**2**	(17)	**(28)**	(6)
Total	**(267)**	(50)	**58**	72

(b) Capital Disclosure

On January 1, 2008, Suncor adopted CICA Handbook section 1535 "Capital Disclosures". This section establishes disclosure requirements for management's policies and processes in defining and managing its capital. There is no financial impact to previously reported financial statements as a result of the implementation of this new standard.

(c) Financial Instruments – Disclosures and Presentation

On January 1, 2008, Suncor adopted CICA Handbook sections 3862 "Financial Instruments – Disclosures" and 3863 "Financial Instruments – Presentation", which enhance existing disclosures for financial instruments. In particular, section 3862 focuses on the identification of risk exposures and the company's approach to management of these risks. There is no financial impact to previously reported financial statements as a result of the implementation of this new standard.

(d) 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. Accordingly, Suncor will be required to report its results under IFRS starting in 2011. We continue to assess the impact of the transition to IFRS on our financial reporting and disclosures. We are developing a full transition plan for compliance, but are not currently able to assess the overall impact of the change. Key disclosures surrounding our transition will be made in our year-end 2008 Consolidated Financial Statements and Management's Discussion and Analysis, consistent with the recent reporting standards requirements release.

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 our annual MD&A, which is to be read in conjunction with our annual consolidated financial statements. For a summarized narrative reconciliation of ROCE calculated on a September 30, 2008 interim basis, please refer to page 40 of our third quarter report to shareholders.

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 September 30, 2008 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 September 30		Nine months ended September 30	
		2008	2007	**2008**	2007
Cash flow from operations ($ millions)	A	**1 346**	957	**3 912**	2 809
Weighted average number of shares outstanding (millions of shares)	B	**934.5**	923.1	**930.4**	921.6
Cash flow from operations ($ per share)	(A/B)	**1.44**	1.04	**4.20**	3.05

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 September 30				Nine months ended September 30			
	2008		2007 [1]		**2008**		2007 [1]	
	$ millions	$/barrel	$ millions	$/barrel	$ millions	$/barrel	$ millions	$/barrel
Operating, selling and general expenses	**799**		604		**2 156**		1 769	
Less: natural gas costs, inventory changes, stock-based compensation and other	**(183)**		(106)		**(341)**		(243)	
Less: non-monetary transactions	**(25)**		(17)		**(81)**		(80)	
Accretion of asset retirement obligations	**14**		10		**41**		30	
Taxes other than income taxes	**24**		15		**57**		39	
Cash costs	**629**	**27.80**	506	23.00	**1 832**	**30.00**	1 515	24.15
Natural gas	**97**	**4.30**	46	2.10	**347**	**5.70**	223	3.55
Imported bitumen (net of other reported product purchases)	**42**	**1.90**	—	—	**107**	**1.75**	3	0.05
Total cash operating costs	**768**	**34.00**	552	25.10	**2 286**	**37.45**	1 741	27.75
Project start-up costs	**8**	**0.35**	24	1.10	**29**	**0.50**	47	0.75
Total cash operating costs after start-up costs	**776**	**34.35**	576	26.20	**2 315**	**37.95**	1 788	28.50
Depreciation, depletion and amortization	**151**	**6.70**	126	5.70	**412**	**6.75**	334	5.30
Total operating costs	**927**	**41.05**	702	31.90	**2 727**	**44.70**	2 122	33.80
Production (thousands of barrels per day)	**245.6**		239.1		**222.6**		229.8	

(1) Prior period amounts have been restated to reflect the change in accounting policy noted on page 15.

Oil Sands Operating Costs – In-Situ Bitumen Production Only

	Three months ended September 30				Nine months ended September 30			
	2008		2007		**2008**		2007	
	$ millions	$/barrel	$ millions	$/barrel	$ millions	$/barrel	$ millions	$/barrel
Operating, selling and general expenses	**78**		67		**243**		204	
Less: natural gas costs and inventory changes	**(42)**		(30)		**(133)**		(100)	
Taxes other than income taxes	**4**		2		**8**		5	
Cash costs	**40**	**10.75**	39	11.85	**118**	**11.75**	109	11.15
Natural gas	**42**	**11.30**	30	9.10	**133**	**13.25**	100	10.25
Cash operating costs	**82**	**22.05**	69	20.95	**251**	**25.00**	209	21.40
In-situ (Firebag) start-up costs	**3**	**0.80**	—	—	**9**	**0.90**	—	—
Total cash operating costs	**85**	**22.85**	69	20.95	**260**	**25.90**	209	21.40
Depreciation, depletion and amortization	**20**	**5.40**	22	6.70	**63**	**6.30**	58	5.95
Total operating costs	**105**	**28.25**	91	27.65	**323**	**32.20**	267	27.35
Production (thousands of barrels per day)	**40.4**		35.8		**36.6**		35.8	

Legal Notice – Forward-Looking Information

This Management's Discussion and Analysis contains certain forward-looking statements 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 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," "invests," "could," "focus," "goal," "proposed," "target," "objective," "potential," "forecast," "predict," "enable," "outlook," 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.

The risks, uncertainties and other factors that could influence actual results have not changed since the 2008 second quarter report other than the additional risk that Suncor's ability to borrow in the capital debt markets at acceptable rates may be affected by market instability. Other risks include but are not limited to, changes in the general economic, market and business conditions; fluctuations in supply and demand for Suncor's products; volatility of and assumptions regarding 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 (for example, the Voyageur project, including our Firebag in-situ development) 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 implementation of recommendations to enhance how the performance of the royalty regime is measured and reported, the Government of Canada's proposed Clean Air regulatory framework and the development of greenhouse gas regulation by other provincial and state governments); the future potential for lawsuits against greenhouse gas emitters, based on links drawn between greenhouse gas emissions and climate change; unexpected issues associated with management and reclamation of our tailings ponds; 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.

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 without charge from the company.

Consolidated statements of earnings and comprehensive income

(unaudited)

($ millions)	Third Quarter 2008	Third Quarter 2007 (restated) (note 2)	Nine months ended September 30 2008	Nine months ended September 30 2007 (restated) (note 2)
Revenues (note 3)	**8 946**	4 802	**22 893**	13 380
Expenses				
Purchases of crude oil and products (note 2)	**2 301**	1 714	**5 499**	4 304
Operating, selling and general (notes 2, 3 and 7)	**998**	814	**2 857**	2 450
Energy marketing and trading activities (note 3)	**3 494**	882	**8 608**	2 323
Transportation and other costs	**61**	46	**175**	134
Depreciation, depletion and amortization	**263**	216	**763**	610
Accretion of asset retirement obligations	**16**	12	**48**	36
Exploration	**30**	9	**73**	78
Royalties (note 11)	**301**	170	**804**	490
Taxes other than income taxes	**170**	165	**487**	487
Loss (gain) on disposal of assets	**4**	(1)	**(14)**	—
Project start-up costs	**8**	26	**29**	52
Financing expenses (income) (note 5)	**156**	(100)	**241**	(185)
	7 802	3 953	**19 570**	10 779
Earnings Before Income Taxes	**1 144**	849	**3 323**	2 601
Provision for Income Taxes (notes 2 and 10)				
Current	**192**	69	**406**	314
Future	**137**	153	**565**	346
	329	222	**971**	660
Net Earnings	**815**	627	**2 352**	1 941
Other comprehensive income (loss) (note 13)	**104**	(76)	**91**	(170)
Comprehensive Income	**919**	551	**2 443**	1 771
Net Earnings per Common Share (dollars), (note 6)				
Basic	**0.87**	0.68	**2.53**	2.11
Diluted	**0.86**	0.66	**2.48**	2.06
Cash dividends	**0.05**	0.05	**0.15**	0.14

See accompanying notes.

Consolidated balance sheets

(unaudited)

($ millions)	September 30 2008	December 31 2007 (restated) (note 2)
Assets		
Current assets		
Cash and cash equivalents	**1 315**	569
Accounts receivable (note 3)	**1 784**	1 438
Inventories (note 2)	**1 349**	1 012
Income taxes receivable	**36**	95
Future income taxes	**67**	46
Total current assets	**4 551**	3 160
Property, plant and equipment, net	**25 213**	20 945
Deferred charges and other (note 3)	**767**	404
Total assets	**30 531**	24 509
Liabilities and Shareholders' Equity		
Current liabilities		
Short-term debt	**7**	6
Accounts payable and accrued liabilities (notes 2, 3 and 11)	**3 148**	2 797
Taxes other than income taxes	**63**	72
Income taxes payable	**69**	244
Future income taxes	**177**	37
Total current liabilities	**3 464**	3 156
Long-term debt (note 12)	**6 568**	3 811
Accrued liabilities and other (notes 3 and 8)	**1 345**	1 434
Future income taxes (notes 2, 3 and 10)	**4 662**	4 212
Shareholders' equity (see below)	**14 492**	11 896
Total liabilities and shareholders' equity	**30 531**	24 509

Shareholders' Equity

	Number (thousands)		Number (thousands)	
Share capital	**934 916**	**1 104**	925 566	881
Contributed surplus		**263**		194
Accumulated other comprehensive loss (note 13)		**(162)**		(253)
Retained earnings (note 2)		**13 287**		11 074
Total shareholders' equity		**14 492**		11 896

See accompanying notes.

Consolidated statements of cash flows

(unaudited)

($ millions)	Third Quarter 2008	Third Quarter 2007 (restated) (note 2)	Nine months ended September 30 2008	Nine months ended September 30 2007 (restated) (note 2)
Operating Activities				
Cash flow from operations	**1 346**	957	**3 912**	2 809
Decrease (increase) in operating working capital				
Accounts receivable	**115**	(136)	**(343)**	(211)
Inventories	**255**	19	**(337)**	(154)
Accounts payable and accrued liabilities	**(546)**	(165)	**136**	29
Taxes payable/receivable	**59**	(55)	**(125)**	152
Cash flow from operating activities	**1 229**	620	**3 243**	2 625
Cash Used in Investing Activities	**(1 893)**	(1 256)	**(5 081)**	(3 678)
Net Cash Deficiency Before Financing Activities	**(664)**	(636)	**(1 838)**	(1 053)
Financing Activities				
Decrease in short-term debt	**—**	(1)	**(1)**	(2)
Net proceeds from issuance of long-term debt	**—**	428	**2 704**	1 835
Net (decrease) increase in long-term debt	**(152)**	18	**(195)**	(469)
Issuance of common shares under stock option plan	**15**	16	**184**	44
Dividends paid on common shares	**(46)**	(42)	**(134)**	(120)
Deferred revenue	**—**	1	**—**	4
Cash flow provided by financing activities	**(183)**	420	**2 558**	1 292
Increase in Cash and Cash Equivalents	**(847)**	(216)	**720**	239
Effect of Foreign Exchange on Cash and Cash Equivalents	**16**	(20)	**26**	(44)
Cash and Cash Equivalents at Beginning of Period	**2 146**	952	**569**	521
Cash and Cash Equivalents at End of Period	**1 315**	716	**1 315**	716

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, 2006, as previously reported	794	100	(71)	8 129
Retroactive adjustment for change in accounting policy (note 2)	—	—	—	132
At December 31, 2006, as restated	794	100	(71)	8 261
Net earnings	—	—	—	1 941
Dividends paid on common shares	—	—	—	(120)
Issued for cash under stock option plan	53	(9)	—	—
Issued under dividend reinvestment plan	9	—	—	(9)
Stock-based compensation expense	—	62	—	—
Income tax benefit of stock option deduction in the U.S.	—	2	—	—
Adjustment to opening retained earnings arising from ineffective portion of cash flow hedges at January 1, 2007	—	—	—	5
Adjustment to opening AOCI arising from effective portion of cash flow hedges at January 1, 2007	—	—	8	—
Change in AOCI related to foreign currency translation	—	—	(186)	—
Change in AOCI related to derivative hedging activities	—	—	16	—
At September 30, 2007, as restated	856	155	(233)	10 078
At December 31, 2007, as previously reported	881	194	(253)	10 791
Retroactive adjustment for change in accounting policy (note 2)	—	—	—	283
At December 31, 2007, as restated	881	194	(253)	11 074
Net earnings	**—**	**—**	**—**	**2 352**
Dividends paid on common shares	**—**	**—**	**—**	**(134)**
Issued for cash under stock option plan	**218**	**(34)**	**—**	**—**
Issued under dividend reinvestment plan	**5**	**—**	**—**	**(5)**
Stock-based compensation expense	**—**	**94**	**—**	**—**
Income tax benefit of stock option deduction in the U.S.	**—**	**9**	**—**	**—**
Change in AOCI related to foreign currency translation	**—**	**—**	**93**	**—**
Change in AOCI related to derivative hedging activities	**—**	**—**	**(2)**	**—**
At September 30, 2008	**1 104**	**263**	**(162)**	**13 287**

See accompanying notes.

Schedules of Segmented Data

(unaudited)

	Third Quarter									
	Oil Sands		Natural Gas		Refining and Marketing		Corporate and Eliminations		Total	
($ millions)	**2008**	2007	**2008**	2007	**2008**	2007	**2008**	2007	**2008**	2007
EARNINGS										
Revenues										
Operating revenues	**2 339**	1 618	**201**	120	**2 841**	2 169	**3**	1	**5 384**	3 908
Energy marketing and trading activities	**—**	—	**—**	—	**3 594**	907	**(44)**	(23)	**3 550**	884
Intersegment revenues	**315**	94	**15**	1	**—**	—	**(330)**	(95)	**—**	—
Interest	**—**	—	**—**	—	**—**	—	**12**	10	**12**	10
	2 654	1 712	**216**	121	**6 435**	3 076	**(359)**	(107)	**8 946**	4 802
Expenses										
Purchases of crude oil and products	**175**	68	**—**	—	**2 516**	1 715	**(390)**	(69)	**2 301**	1 714
Operating, selling and general	**799**	604	**44**	35	**170**	160	**(15)**	15	**998**	814
Energy marketing and trading activities	**—**	—	**—**	—	**3 495**	906	**(1)**	(24)	**3 494**	882
Transportation and other costs	**48**	32	**6**	6	**7**	8	**—**	—	**61**	46
Depreciation, depletion and amortization	**151**	126	**59**	43	**40**	38	**13**	9	**263**	216
Accretion of asset retirement obligations	**14**	10	**2**	2	**—**	—	**—**	—	**16**	12
Exploration	**7**	—	**23**	9	**—**	—	**—**	—	**30**	9
Royalties (note 11)	**249**	145	**52**	25	**—**	—	**—**	—	**301**	170
Taxes other than income taxes	**28**	24	**2**	1	**140**	140	**—**	—	**170**	165
Loss (gain) on disposal of assets	**11**	—	**2**	(1)	**(2)**	—	**(7)**	—	**4**	(1)
Project start-up costs	**8**	24	**—**	—	**—**	2	**—**	—	**8**	26
Financing expenses (income)	**—**	—	**—**	—	**—**	—	**156**	(100)	**156**	(100)
	1 490	1 033	**190**	120	**6 366**	2 969	**(244)**	(169)	**7 802**	3 953
Earnings (loss) before income taxes	**1 164**	679	**26**	1	**69**	107	**(115)**	62	**1 144**	849
Income taxes	**(310)**	(185)	**(8)**	(1)	**(23)**	(38)	**12**	2	**(329)**	(222)
Net earnings (loss)	**854**	494	**18**	—	**46**	69	**(103)**	64	**815**	627

Schedules of Segmented Data (continued)

(unaudited)

	Third Quarter									
	Oil Sands		Natural Gas		Refining and Marketing		Corporate and Eliminations		Total	
($ millions)	**2008**	2007	**2008**	2007	**2008**	2007	**2008**	2007	**2008**	2007
CASH FLOW BEFORE FINANCING ACTIVITIES										
Cash flow from (used in) operating activities:										
Cash flow from (used in) operations										
Net earnings (loss)	**854**	494	**18**	—	**46**	69	**(103)**	64	**815**	627
Exploration expenses	**—**	—	**19**	2	**—**	—	**—**	—	**19**	2
Non-cash items included in earnings										
Depreciation, depletion and amortization	**151**	126	**59**	43	**40**	38	**13**	9	**263**	216
Future income taxes	**149**	140	**4**	—	**(8)**	13	**(8)**	—	**137**	153
Loss (gain) on disposal of assets	**11**	—	**2**	(1)	**(2)**	—	**(7)**	—	**4**	(1)
Stock-based compensation expense	**12**	12	**1**	1	**4**	7	**8**	4	**25**	24
Other	**(13)**	—	**—**	2	**4**	—	**145**	(122)	**136**	(120)
Increase (decrease) in deferred credits and other	**(55)**	57	**—**	—	**1**	(1)	**1**	—	**(53)**	56
Total cash flow from (used in) operations	**1 109**	829	**103**	47	**85**	126	**49**	(45)	**1 346**	957
Decrease (increase) in operating working capital	**647**	75	**105**	1	**(706)**	(169)	**(163)**	(244)	**(117)**	(337)
Total cash flow from (used in) operating activities	**1 756**	904	**208**	48	**(621)**	(43)	**(114)**	(289)	**1 229**	620
Cash from (used in) investing activities:										
Capital and exploration expenditures	**(1 732)**	(1 227)	**(77)**	(67)	**(49)**	(101)	**(11)**	(22)	**(1 869)**	(1 417)
Deferred maintenance shutdown expenditures	**(59)**	(42)	**(3)**	—	**(28)**	(16)	**—**	—	**(90)**	(58)
Deferred outlays and other investments	**(6)**	—	**—**	—	**—**	2	**3**	(16)	**(3)**	(14)
Proceeds from disposals	**—**	—	**1**	5	**—**	—	**7**	—	**8**	5
Decrease (increase) in investing working capital	**69**	224	**—**	—	**(1)**	4	**(7)**	—	**61**	228
Total cash (used in) investing activities	**(1 728)**	(1 045)	**(79)**	(62)	**(78)**	(111)	**(8)**	(38)	**(1 893)**	(1 256)
Net cash surplus (deficiency) before financing activities	**28**	(141)	**129**	(14)	**(699)**	(154)	**(122)**	(327)	**(664)**	(636)

Schedules of Segmented Data (continued)

(unaudited)

Nine months ended September 30

($ millions)	Oil Sands 2008	Oil Sands 2007	Natural Gas 2008	Natural Gas 2007	Refining and Marketing 2008	Refining and Marketing 2007	Corporate and Eliminations 2008	Corporate and Eliminations 2007	Total 2008	Total 2007
EARNINGS										
Revenues										
Operating revenues	**6 022**	4 395	**572**	400	**7 642**	6 206	**13**	4	**14 249**	11 005
Energy marketing and trading activities	**—**	—	**—**	—	**8 728**	2 376	**(109)**	(25)	**8 619**	2 351
Intersegment revenues	**1 045**	388	**45**	9	**—**	—	**(1 090)**	(397)	**—**	—
Interest	**—**	—	**—**	—	**—**	4	**25**	20	**25**	24
	7 067	4 783	**617**	409	**16 370**	8 586	**(1 161)**	(398)	**22 893**	13 380
Expenses										
Purchases of crude oil and products	**336**	137	**—**	—	**6 311**	4 534	**(1 148)**	(367)	**5 499**	4 304
Operating, selling and general	**2 156**	1 769	**123**	112	**527**	511	**51**	58	**2 857**	2 450
Energy marketing and trading activities	**—**	—	**—**	—	**8 612**	2 350	**(4)**	(27)	**8 608**	2 323
Transportation and other costs	**140**	96	**13**	15	**22**	23	**—**	—	**175**	134
Depreciation, depletion and amortization	**412**	334	**169**	128	**148**	117	**34**	31	**763**	610
Accretion of asset retirement obligations	**41**	30	**6**	5	**1**	1	**—**	—	**48**	36
Exploration	**16**	13	**57**	65	**—**	—	**—**	—	**73**	78
Royalties (note 11)	**661**	401	**143**	89	**—**	—	**—**	—	**804**	490
Taxes other than income taxes	**81**	65	**5**	4	**400**	417	**1**	1	**487**	487
Loss (gain) on disposal of assets	**13**	—	**(22)**	(1)	**2**	1	**(7)**	—	**(14)**	—
Project start-up costs	**29**	47	**—**	—	**—**	5	**—**	—	**29**	52
Financing expenses (income)	**—**	—	**—**	—	**—**	—	**241**	(185)	**241**	(185)
	3 885	2 892	**494**	417	**16 023**	7 959	**(832)**	(489)	**19 570**	10 779
Earnings (loss) before income taxes	**3 182**	1 891	**123**	(8)	**347**	627	**(329)**	91	**3 323**	2 601
Income taxes	**(882)**	(453)	**(34)**	8	**(115)**	(214)	**60**	(1)	**(971)**	(660)
Net earnings (loss)	**2 300**	1 438	**89**	—	**232**	413	**(269)**	90	**2 352**	1 941
As at September 30										
TOTAL ASSETS	**23 161**	16 739	**1 807**	1 724	**5 681**	4 545	**(118)**	(229)	**30 531**	22 779

Schedules of Segmented Data (continued)

(unaudited)

	Oil Sands		Natural Gas		Refining and Marketing		Corporate and Eliminations		Total	
Nine months ended September 30										
($ millions)	2008	2007	2008	2007	2008	2007	2008	2007	2008	2007
CASH FLOW BEFORE FINANCING ACTIVITIES										
Cash flow from (used in) operating activities:										
Cash flow from (used in) operations										
Net earnings (loss)	2 300	1 438	89	—	232	413	(269)	90	2 352	1 941
Exploration expenses	—	—	48	54	—	—	—	—	48	54
Non-cash items included in earnings										
Depreciation, depletion and amortization	412	334	169	128	148	117	34	31	763	610
Future income taxes	515	252	20	(8)	72	106	(42)	(4)	565	346
Loss (gain) on disposal of assets	13	—	(22)	(1)	2	1	(7)	—	(14)	—
Stock-based compensation expense	47	30	3	3	15	15	29	14	94	62
Other	(29)	(13)	(3)	6	14	—	185	(237)	167	(244)
Increase (decrease) in deferred credits and other	(65)	45	—	(1)	2	(4)	—	—	(63)	40
Total cash flow from (used in) operations	3 193	2 086	304	181	485	648	(70)	(106)	3 912	2 809
Decrease (increase) in operating working capital	183	422	41	12	(542)	(239)	(351)	(379)	(669)	(184)
Total cash flow from (used in) operating activities	3 376	2 508	345	193	(57)	409	(421)	(485)	3 243	2 625
Cash from (used in) investing activities:										
Capital and exploration expenditures	(4 581)	(3 138)	(241)	(425)	(103)	(224)	(20)	(42)	(4 945)	(3 829)
Deferred maintenance shutdown expenditures	(318)	(98)	(5)	(1)	(49)	(28)	—	—	(372)	(127)
Deferred outlays and other investments	(37)	1		—		—	1	(16)	(36)	(15)
Proceeds from disposals	—	—	26	5	—	1	7	—	33	6
Decrease (increase) in investing working capital	260	314	—	—	(14)	(27)	(7)	—	239	287
Total cash (used in) investing activities	(4 676)	(2 921)	(220)	(421)	(166)	(278)	(19)	(58)	(5 081)	(3 678)
Net cash surplus (deficiency) before financing activities	(1 300)	(413)	125	(228)	(223)	131	(440)	(543)	(1 838)	(1 053)

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 changes as described in note 2, Changes 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 September 30, 2008 and the results of its operations and cash flows for the three and nine month periods ended September 30, 2008 and 2007.

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

2. CHANGES IN ACCOUNTING POLICIES

(a) Inventories

On January 1, 2008, the company retroactively adopted the Canadian Institute of Chartered Accountants (CICA) Handbook section 3031 "Inventories". Under the new standard, the use of a LIFO (last-in-first-out) based valuation approach for inventory has been eliminated. The standard also required any impairment to net realizable value of inventory to be written down at each reporting period, with subsequent reversals when applicable. The company transitioned to a FIFO (first-in-first-out) based valuation approach for inventory effective January 1, 2008. The impact of adopting this accounting standard is as follows:

Change in Consolidated Balance Sheets

($ millions, increase/(decrease))	**As at September 30 2008**	As at December 31 2007
Inventories	**473**	404
Total assets	**473**	404
Accounts payable and accrued liabilities	**(25)**	—
Future income taxes	**157**	121
Retained earnings	**341**	283
Total liabilities and shareholders' equity	**473**	404

Change in Consolidated Statements of Earnings and Comprehensive Income

	Third quarter		Nine months ended September 30	
($ millions, increase/(decrease))	**2008**	2007	**2008**	2007
Purchases of crude oil and products	**191**	(19)	**(144)**	(94)
Operating, selling and general	**186**	89	**50**	(14)
Future income taxes	**(110)**	(20)	**36**	36
Net earnings	**(267)**	(50)	**58**	72
Per common share – basic (dollars)	**(0.28)**	(0.05)	**0.06**	0.08
Per common share – diluted (dollars)	**(0.28)**	(0.05)	**0.06**	0.08

(b) Capital Disclosure

On January 1, 2008, the company adopted CICA Handbook section 1535 "Capital Disclosures". This section establishes disclosure requirements for management's policies and processes in defining and managing its capital. There was no financial impact to previously reported financial statements as a result of the implementation of this new standard.

(c) Financial Instruments – Disclosures and Presentation

On January 1, 2008, the company adopted CICA Handbook sections 3862 "Financial Instruments – Disclosures" and 3863 "Financial Instruments – Presentation", which enhance existing disclosures for financial instruments. In particular, section 3862 focuses on the identification of risk exposures and the company's approach to management of these risks. There was no financial impact to previously reported financial statements as a result of the implementation of this new standard.

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, foreign currency exchange rates, or interest 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.

Financial Instruments

(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 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 September 30, 2008, the carrying value of our fixed-term debt accounted for under the amortized cost method was $5.8 billion (fair value – $4.9 billion).

(b) Hedges – Documented as Part of a Qualifying Hedge Relationship

Fair Value Hedges

Suncor periodically enters into derivative financial instrument contracts such as interest rate swaps as part of its risk management strategy to manage its exposure to benchmark interest rate fluctuations. The interest rate swap contracts involve an exchange of floating rate versus fixed rate interest payments between the company and investment grade counterparties. The differentials on the exchange of periodic interest payments are recognized in the accounts as an adjustment to interest expense. The fair value of the underlying debt is adjusted by the fair value change in the derivative financial instrument with the offset to interest expense. At September 30, 2008, the company had interest rate derivatives classified as fair value hedges outstanding for up to 3 years relating to fixed-rate debt. There was no ineffectiveness recognized on interest rate swaps designated as fair value hedges during the three and nine month periods ended September 30, 2008 (no ineffectiveness during the three and nine month periods ended September 30, 2007). The fair value of interest rate swap contracts outstanding at September 30, 2008 is detailed in note 12, Long-term debt.

The company periodically enters into derivative contracts to hedge risks specific to individual transactions. The differentials between the fair value of the hedged transactions and the fair value of the derivative contracts are recognized in the accounts as an adjustment to operating revenues. The earnings impact associated with hedge ineffectiveness on derivative contracts to hedge risks specific to individual transactions during the three month period ended September 30, 2008 was a loss of $1 million, net of income taxes of $1 million (2007 – nil). During the nine month period ended September 30, 2008, the earnings impact was a loss of $4 million, net of income taxes of $2 million (2007 – nil).

Cash Flow Hedges

Suncor operates in a global industry where the market price of its petroleum and natural gas products is largely determined based on floating benchmark indices. The company periodically enters into derivative financial instrument contracts such as forwards, futures, swaps, options and costless collars to hedge against the potential adverse impact of changing market prices due to changes in the underlying indices. Specifically, the company manages crude sales price variability by entering into West Texas Intermediate (WTI) derivative transactions, and manages variability in market interest rates and foreign exchange rates during periods of debt issuance through the use of interest rate locks and foreign exchange forward contracts.

At September 30, 2008, the company had hedged a portion of its forecasted U.S. dollar denominated cash flows subject to U.S. dollar WTI commodity risk for 2008, as well as cash flows related to natural gas production in 2008.

There was no earnings impact associated with realized and unrealized hedge ineffectiveness on derivative contracts designated as cash flow hedges during the three month period ended September 30, 2008 (2007 – gain of $2 million), and there was also no earnings impact during the nine month period ended September 30, 2008 (2007 – loss of $4 million, net of income taxes of $2 million).

Certain derivative contracts do not require the payment of premiums or cash margin deposits prior to settlement. On settlement, these contracts result in cash receipts or payments by the company for the difference between the contract and market rates for the applicable dollars and volumes hedged during the contract term. Such cash receipts or payments offset corresponding decreases or increases in the company's sales revenues or crude oil purchase costs. For collars, if market rates are not different than, or are within the range of contract prices, the options contracts making up the collar will expire with no exchange of cash.

Revenue hedge contracts outstanding at September 30, 2008 were as follows:

Crude Oil	Quantity (bpd)	Average Price (US$/bbl) [(a)]	Revenue Hedged (Cdn$ millions) [(b)]	Hedge Period [(c)]
Costless collars	**10 000**	**59.85 - 101.06**	**58 - 99**	**2008**

Natural Gas	Quantity (GJ/day)	Average Price (Cdn$/GJ)	Revenue Hedged (Cdn$ millions)	Hedge Period [(d)]
Costless collars	**15 000**	**7.00 - 8.71**	**3 - 4**	**2008**

(a) Average price for crude oil costless collars is US$ WTI per barrel at Cushing, Oklahoma.

(b) The revenue hedged is translated to Cdn$ at the September 30, 2008 exchange rate for convenience purposes.

(c) Original hedge term is for the full year.

(d) For the period of October 2008, inclusive.

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)	**September 30 2008**	December 31 2007
Revenue hedge collars	**(6)**	(11)
Fixed to floating interest rate swaps	**13**	8
Specific hedges of individual transactions	**4**	12
Fair value of outstanding hedging derivative financial instruments	**11**	9

Accumulated Other Comprehensive Income (AOCI)

A reconciliation of changes in AOCI attributable to derivative hedging activities for the nine month period ending September 30, 2008 is as follows:

($ millions)	**2008**
AOCI attributable to derivatives and hedging activities, at December 31, 2007, net of income taxes of $4	13
Current year net changes arising from cash flow hedges, net of income taxes of $3	(7)
Net unrealized hedging losses at the beginning of the year reclassified to earnings during the period, net of income taxes of $2	5
AOCI attributable to derivatives and hedging activities, at September 30, 2008, net of income taxes of $3	11

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

Suncor 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 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 and, as such, these derivative instruments are recorded at fair value at each balance sheet date. The earnings impact associated with these contracts for the three month period ended September 30, 2008, was a gain of $54 million, net of income taxes of $22 million (2007 – a gain of less than $1 million, net of income taxes of less than $1 million). During the nine month period ended September 30, 2008, the earnings impact was a loss of $6 million net of income taxes of $2 million (2007 – a loss of $2 million, net of income taxes of $1 million).

Significant contracts outstanding at September 30 were as follows:

Crude Oil [d]	Quantity (bpd)	Price (US$/bbl) [a]	Revenue Hedged (Cdn$ millions) [b]	Hedge Period [c]
Purchased puts	**55 000**	**60.00**	**1 277**	**2009**
Purchased puts	**55 000**	**60.00**	**1 277**	**2010**

(a) Price for crude puts is US$ WTI per barrel at Cushing, Oklahoma.

(b) The revenue hedged is translated to Cdn$ at the September 30, 2008 exchange rate for convenience purposes.

(c) Original hedge term is for the full year.

(d) Premium paid was US$59 million.

(d) Energy Marketing and 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 and marketing revenues. These energy contracts are comprised of crude oil, natural gas, heating oil and gasoline contracts. Financial energy trading activities are accounted for using the mark-to-market method. Physical energy marketing contracts involve activities intended to enhance prices and satisfy physical deliveries to customers. The results of these activities are reported as revenue and as energy marketing and trading expenses in the Consolidated Statements of Earnings

Quarterly operating summary

(unaudited)

	For the quarter ended					Nine months ended		Total year
	Sept 30 2008	June 30 2008	Mar 31 2008	Dec 31 2007	Sept 30 2007	**Sept 30 2008**	Sept 30 2007	Dec 31 2007
OIL SANDS								
Production [1],[a]								
Total production	**245.6**	174.6	248.0	252.5	239.1	**222.6**	229.8	235.6
Firebag	**40.4**	34.7	34.6	40.4	35.8	**36.6**	35.8	36.9
Sales [a]								
Light sweet crude oil	**48.1**	68.2	96.2	102.2	99.3	**70.7**	101.6	101.7
Diesel	**10.9**	21.2	28.0	26.0	23.9	**20.0**	24.6	25.0
Light sour crude oil	**157.4**	91.8	120.8	118.2	94.1	**123.4**	96.9	102.3
Bitumen	**2.6**	0.3	0.1	5.4	6.6	**1.0**	5.7	5.7
Total sales	**219.0**	181.5	245.1	251.8	223.9	**215.1**	228.8	234.7
Average sales price [2], [b]								
Light sweet crude oil	**121.96**	122.12	100.93	87.34	81.00	**112.52**	74.87	78.03
Other (diesel, light sour crude oil and bitumen)	**114.74**	120.52	93.09	78.48	73.76	**108.83**	67.84	70.86
Total	**116.32**	121.12	96.16	82.07	76.97	**110.04**	71.02	74.01
Total *	**117.14**	122.39	96.22	82.36	76.97	**110.70**	70.99	74.07
Cash operating costs and Total operating costs – Total operations [c]								
Cash costs	**27.80**	40.10	25.10	24.10	23.00	**30.00**	24.15	24.15
Natural gas	**4.30**	8.75	5.00	3.60	2.10	**5.70**	3.55	3.55
Imported bitumen	**1.90**	2.00	1.45	0.20	—	**1.75**	0.05	0.10
Cash operating costs [3]	**34.00**	50.85	31.55	27.90	25.10	**37.45**	27.75	27.80
Project start-up costs	**0.35**	0.90	0.30	0.55	1.10	**0.50**	0.75	0.95
Total cash operating costs [4]	**34.35**	51.75	31.85	28.45	26.20	**37.95**	28.50	28.75
Depreciation, depletion and amortization	**6.70**	8.30	5.75	5.60	5.70	**6.75**	5.30	5.40
Total operating costs [5]	**41.05**	60.05	37.60	34.05	31.90	**44.70**	33.80	34.15
Cash operating costs and Total operating costs – In-situ bitumen production only [c]								
Cash costs	**10.75**	10.10	14.60	9.95	11.85	**11.75**	11.15	10.85
Natural gas	**11.30**	14.55	14.10	9.15	9.10	**13.25**	10.25	9.90
Cash operating costs [6]	**22.05**	24.65	28.70	19.10	20.95	**25.00**	21.40	20.75
In-situ (Firebag) start-up costs	**0.80**	1.65	0.35	—	—	**0.90**	—	—
Total cash operating costs [7]	**22.85**	26.30	29.05	19.10	20.95	**25.90**	21.40	20.75
Depreciation, depletion and amortization	**5.40**	6.70	6.75	6.80	6.70	**6.30**	5.95	6.20
Total operating costs [8]	**28.25**	33.00	35.80	25.90	27.65	**32.20**	27.35	26.95
(for the period ended)								
Capital employed [i]	**9 035**	7 716	6 837	6 605	6 071			
(for the twelve months ended)								
Return on capital employed [j]	**46.0**	43.6	44.3	43.0	32.3			
Return on capital employed [j]****	**28.6**	27.3	28.0	27.9	21.7			

Quarterly operating summary (continued)

(unaudited)

	For the quarter ended					Nine months ended		Total year
	Sept 30 2008	June 30 2008	Mar 31 2008	Dec 31 2007	Sept 30 2007	**Sept 30 2008**	Sept 30 2007	Dec 31 2007
NATURAL GAS								
Gross production **								
Natural gas (d)	**197**	205	209	210	193	**204**	192	196
Natural gas liquids and crude oil (a)	**2.6**	3.4	3.3	3.2	3.1	**3.1**	3.1	3.1
Total gross production (e)	**35.4**	37.7	38.2	38.2	35.2	**37.1**	35.0	35.8
Total gross production (f)	**213**	226	229	229	211	**223**	210	215
Average sales price (2)								
Natural gas (g)	**9.10**	9.62	7.30	6.08	5.39	**8.66**	6.41	6.32
Natural gas (g) *	**9.14**	9.68	7.31	6.02	5.14	**8.70**	6.37	6.27
Natural gas liquids and crude oil (b)	**96.88**	86.14	64.14	60.31	58.11	**81.37**	55.33	56.64
Net wells drilled								
Conventional – exploratory ***	**4**	2	2	6	1	**8**	7	14
– development	**6**	6	7	6	2	**19**	12	17
	10	8	9	12	3	**27**	19	31
(for the period ended)								
Capital employed (i)	**1 120**	1 226	1 175	1 153	1 090			
(for the twelve months ended)								
Return on capital employed (j)	**10.3**	8.3	3.5	2.5	(0.6)			
REFINING AND MARKETING								
Refined product sales (h)								
Transportation fuels								
Gasoline – retail	**4.5**	4.5	4.6	4.9	5.1	**4.6**	5.3	5.2
– other	**11.5**	11.8	10.8	11.0	12.0	**11.3**	11.9	11.6
Distillate	**10.6**	11.5	10.4	11.0	10.8	**10.8**	10.5	10.6
Total transportation fuel sales	**26.6**	27.8	25.8	26.9	27.9	**26.7**	27.7	27.4
Petrochemicals	**1.0**	0.9	0.6	0.7	0.9	**0.8**	1.0	0.9
Asphalt	**1.9**	1.7	2.2	1.4	2.1	**1.9**	1.7	1.7
Other	**2.5**	2.7	1.9	3.8	4.2	**2.3**	3.4	3.5
Total refined product sales	**32.0**	33.1	30.5	32.8	35.1	**31.7**	33.8	33.5
Crude oil supply and refining								
Processed at refineries (h)	**25.1**	26.0	23.0	22.1	25.9	**24.7**	26.1	25.1
Utilization of refining capacity (j)	**99**	102	90	87	102	**97**	102	98
(for the period ended)								
Capital employed (i)	**3 289**	2 534	2 837	2 489	2 332			
(for the twelve months ended)								
Return on capital employed (j)	**9.3**	12.6	18.3	20.0	20.9			
Return on capital employed (j) ****	**9.0**	11.6	16.5	17.4	17.9			

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.
(2) Average sales price	–	This operating statistic is calculated before royalties and net of related transportation costs (including or excluding the impact of hedging activities as noted).
(3) Cash operating costs – 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 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
(b) dollars per barrel
(c) dollars per barrel rounded to the nearest $0.05
(d) millions of cubic feet per day
(e) thousands of barrels of oil equivalent per day
(f) millions of cubic feet equivalent per day
(g) dollars per thousand cubic feet
(h) thousands of cubic metres per day
(i) $ millions
(j) percentage

Metric Conversion

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

SUNCOR
ENERGY

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