THIRD QUARTER 2007

Report to shareholders for the period ended September 30, 2007

FIRST IN oil sands
STILL taking the lead

Suncor Energy reports strong financial results for third quarter

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 2007 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 2007 earnings of $588 million ($1.27 per common share) excluding the impact of unrealized foreign exchange gains on the company's U.S. dollar denominated long-term debt and project start-up costs, compared to $691 million ($1.50 per common share) in the third quarter of 2006. Net earnings for the third quarter of 2007 were $677 million ($1.47 per common share), compared to $682 million ($1.48 per common share) in the third quarter of 2006. Cash flow from operations was $1.027 billion in the third quarter of 2007, compared to $1.153 billion in the third quarter of 2006.

The decrease in net earnings was primarily due to a reduction in oil sands sales volumes and increased downstream refined product purchases; both the result of planned maintenance outages. Sales were down in oil sands due to a planned maintenance outage in July that impacted production rates,

Net Earnings by Quarter
($ millions)

2007 Q3	2006 Q3	**2007 YTD**	2006 YTD
677	682	**1 869**	2 613

Cash Flow from Operations by Quarter
($ millions)

2007 Q3	2006 Q3	**2007 YTD**	2006 YTD
1 027	1 153	**2 701**	3 787

Production
(thousands of barrels of oil equivalent per day)

	2007 Q3	2006 Q3	**2007 YTD**	2006 YTD
Natural Gas	**35.2**	34.6	**35.0**	35.2
Oil Sands	**239.1**	242.8	**229.8**	258.1
Total	**274.3**	277.4	**264.8**	293.3

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

	2007	2006
Return on average shareholder's equity	**24.0**	47.7
Return on capital employed	**24.0**	47.2

while refined product purchases were increased to ensure customer requirements were met during a planned outage at the Sarnia refinery in September. These negative impacts were partially offset by higher price realizations for oil sands products. Cash flow from operations was lower partially due to the same factors that impacted net earnings, as well as an increase in cash income tax expenses in the third quarter of 2007, compared to the third quarter of 2006.

"If you back out the impact of the maintenance work, you'll see that from an operational perspective, both our oil sands operation and our downstream businesses had a good quarter," said Rick George, president and chief executive officer. "Production at oil sands and utilization rates in the downstream were fairly strong."

Earnings for the first nine months of 2007 were $1.640 billion ($3.56 per common share) excluding the impacts of income tax rate revaluations, net insurance proceeds (relating to the January 2005 fire), unrealized foreign exchange gains on the company's U.S. dollar denominated long-term debt, and project start-up costs, compared to $1.972 billion ($4.30 per common share) in the same period for 2006. Net earnings for the first nine months of 2007 were $1.869 billion ($4.06 per common share), compared to $2.613 billion ($5.69 per common share) for the same period in 2006. Earnings decreased as a result of increased maintenance and lower production at oil sands during the first nine months of 2007, compared to the same period in 2006.

Cash flow from operations for the first nine months of 2007 was $2.701 billion, compared to $3.787 billion in the first nine months of 2006. Cash flow from operations was lower partially due to the same factors that impacted net earnings, as well as an increase in cash income tax expenses in the first nine months of 2007 compared to the first nine months of 2006.

Suncor's total upstream production averaged 274,300 barrels of oil equivalent (boe) per day in the third quarter of 2007, compared to 277,400 boe per day in the third quarter of 2006. Oil sands production contributed 239,100 barrels per day (bpd) in the third quarter of 2007, compared to 242,800 bpd in the third quarter of 2006. In Suncor's natural gas business, production was 211 million cubic feet equivalent (mmcfe) per day, compared to third quarter 2006 production of 208 mmcfe per day.

Oil sands cash operating costs in the third quarter of 2007 averaged $25.10 per barrel, compared to $23.70 per barrel during the third quarter of 2006. The increase in cash operating costs per barrel was primarily due to higher maintenance costs and slightly lower production resulting from the July outage.

"At oil sands we saw major improvements during the latter half of the quarter. We used the outage to tie-in new operating units and we saw production rates climb considerably after start-up," said George. "It's a good indicator that we can expect a strong fourth quarter and that we'll have a great start to 2008."

The tie-ins completed are key to increasing production capacity to 350,000 bpd in 2008.

Despite the gains in the third quarter, unscheduled outages throughout the year have impacted year-to-date results at oil sands. As a result, management has changed its outlook, targeting an annual production average of 240,000 bpd to 245,000 bpd and cash operating cost of $26.50 to $27.00 per barrel.

"This remains a complex business with many day-to-day challenges and uncertainties," said George. "We must increase our focus on achieving operational excellence."

This includes making progress to address issues at Suncor's Firebag in-situ operation where high emissions have resulted in intervention by both Alberta Environment and the Alberta Energy and Utilities Board. Until emissions are reduced, production at Suncor's in-situ operation has been capped by regulators at approximately 42,000 barrels of bitumen per day. Suncor's revised outlook reflects this constraint.

"We're taking a number of steps to address regulator concerns including accelerating the construction of emission abatement equipment," said George. "At the same time we're also examining ways to increase bitumen supply from our mining operations to help offset supply restraints at Firebag."

In Suncor's downstream operations, work continues on modifications to the Sarnia refinery that are expected to enable the facility to process up to 40,000 bpd of oil sands sour crude. A partial outage to tie-in new facilities, which began in early September, is expected to be completed in the fourth quarter of 2007.

Planned maintenance at portions of the Commerce City refinery is also underway, and is expected to conclude by the end of October. The refinery is expected to operate at reduced rates during the outage.

"We must increase our focus on achieving operational excellence."

Rick George, president and chief executive officer

Outlook

Suncor's outlook provides management's targets for 2007 in certain key areas of the company's business. Outlook forecasts are subject to change.

	Nine months ended September 30, 2007	2007 Full Year Outlook
Oil Sands		
Production (bpd) (1)	**229 800**	240 000 to 245 000
Diesel	**11%**	10%
Sweet	**44%**	42%
Sour	**42%**	43%
Bitumen	**3%**	5%
Realization on crude sales basket (2)	**WTI @ Cushing less Cdn$2.10 per barrel**	WTI @ Cushing less Cdn$2.75 to $3.75 per barrel
Cash operating costs (3)	**$27.75 per barrel**	$26.50 to $27.00 per barrel
Natural Gas		
Production (mmcf equivalent per day) (4)	**210**	215 to 220

1) The 2007 oil sands production outlook has been revised from the original target of 260,000 bpd to 270,000 bpd. The revised target is based on a production goal of 275,000 bpd to 285,000 bpd for the fourth quarter of 2007. The 2007 oil sands production target includes non-upgraded bitumen sold directly to the market. In 2006, the production target referred only to synthetic crude oil production.

2) The 2007 realization on crude sales basket outlook was revised from the original target of WTI @ Cushing less Cdn$7.50 to $8.50 per barrel.

3) The 2007 cash operating cost outlook was revised from the original target of $21.50 to $22.50 per barrel. The revised target is based on a cash operating cost goal of $23.50 to $24.50 per barrel in the fourth quarter of 2007. Cash operating cost estimates are based on the following assumptions: i) annual average production of 240,000 bpd to 245,000 bpd; ii) a production mix as described in the chart above; and iii) a natural gas price of US$7.00 per thousand cubic feet (mcf) at Henry Hub. 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. See "Non-GAAP Financial Measures" on page 13 of Suncor's third quarter 2007 Report to Shareholders.

4) The 2007 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.

Factors that could potentially impact Suncor's financial performance include:

- Alberta provincial royalty review. The specific impacts of proposed changes to the Alberta royalty legislation are not yet known, however, it is expected that royalties as a percentage of revenues will increase.
- Regulatory intervention at the Firebag in-situ operation. Additional maintenance and capital costs will be incurred to construct and commission emission abatement equipment.
- Crude oil hedges. Suncor has hedging agreements for 60,000 bpd in 2007 and 10,000 bpd in 2008. These costless collar hedges have an average floor of approximately US$51.64 per barrel in 2007 while allowing participation in higher crude oil prices with an average ceiling of approximately US$101.06 per barrel in 2008.

Information on risks, uncertainties and other factors that could affect these plans is included in Suncor's annual report to shareholders and other documents filed with regulatory authorities.

Management's discussion and analysis

October 25, 2007

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. Actual results may differ materially. See page 15 for additional information.

This MD&A should be read in conjunction with our September 30, 2007 unaudited interim consolidated financial statements and notes. Readers should also refer to our MD&A on pages 18 to 60 of our 2006 Annual Report and to our Annual Information Form (AIF), dated February 28, 2007. 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 58 of our 2006 Annual Report, and page 13 of this MD&A.

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

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

References to "we," "our," "us," "Suncor," or "the company" mean Suncor Energy Inc., its subsidiaries, partnerships and joint venture investments, unless the context requires otherwise.

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 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 estimates only. The actual amounts may differ and these differences may be material. For a further discussion of our significant capital projects and the range of cost estimates associated with an "on-budget" project, see "Significant Capital Project Update" on page 11.

Selected financial information

Industry Indicators (average for the period)	Three months ended September 30 **2007**	2006	Nine months ended September 30 **2007**	2006
West Texas Intermediate (WTI) crude oil US$/barrel at Cushing	**75.40**	70.50	**66.20**	68.20
Canadian 0.3% par crude oil Cdn$/barrel at Edmonton	**80.25**	79.40	**73.10**	75.60
Light/heavy crude oil differential US$/barrel				
WTI at Cushing less Western Canadian Select at Hardisty	**22.85**	18.80	**19.60**	21.60
Natural Gas US$/mcf at Henry Hub	**6.15**	6.55	**6.90**	7.45
Natural Gas (Alberta spot) Cdn$/mcf at AECO	**5.60**	6.05	**6.80**	7.20
New York Harbour 3-2-1 crack (1) US$/barrel	**11.95**	10.20	**15.40**	10.65
Exchange rate: Cdn$:US$	**0.96**	0.89	**0.91**	0.89

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

Outstanding Share Data (as at September 30, 2007)	
Common shares	461 940 543
Common share options – total	27 871 518
Common share options – exercisable	8 076 247

Summary of Quarterly Results

	2007 three months ended			2006 three months ended				2005 three months ended
($ millions, except per share data)	**Sept. 30**	June 30	Mar. 31	Dec. 31	Sept. 30	June 30	Mar. 31	Dec. 31
Revenues	**4 666**	4 358	3 951	3 787	4 114	4 070	3 858	3 521
Net earnings	**677**	641	551	358	682	1 218	713	693
Net earnings attributable to common shareholders per share								
Basic	**1.47**	1.39	1.20	0.78	1.48	2.65	1.56	1.52
Diluted	**1.43**	1.36	1.17	0.76	1.45	2.59	1.52	1.48

Analysis of Consolidated Statements of Earnings and Cash Flows

Net earnings for the third quarter of 2007 were $677 million ($1.47 per common share), compared to $682 million ($1.48 per common share) in the third quarter of 2006. Excluding the impact of unrealized foreign exchange gains on the company's U.S. dollar denominated long-term debt and project start-up costs, earnings for the third quarter of 2007 were $588 million ($1.27 per common share), compared to $691 million ($1.50 per common share) in the third quarter of 2006.

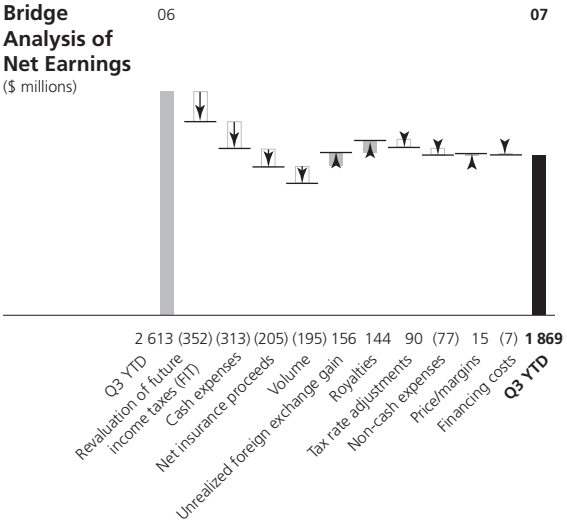
The decrease in net earnings was primarily due to a reduction in oil sands sales volumes and increased downstream refined product purchases; both the result of planned maintenance outages. Sales were down in oil sands because a planned maintenance outage in July impacted production rates, while refined product purchases were increased to ensure customer requirements were met during a planned outage at the Sarnia refinery. These negative impacts were partially offset by higher price realizations for oil sands products.

Cash flow from operations in the third quarter of 2007 was $1.027 billion, compared to $1.153 billion in the same period of 2006. Cash flow from operations was lower partially due to the same factors that impacted net earnings, as well as an increase in cash income tax expenses in the third quarter of 2007, compared to the third quarter of 2006.

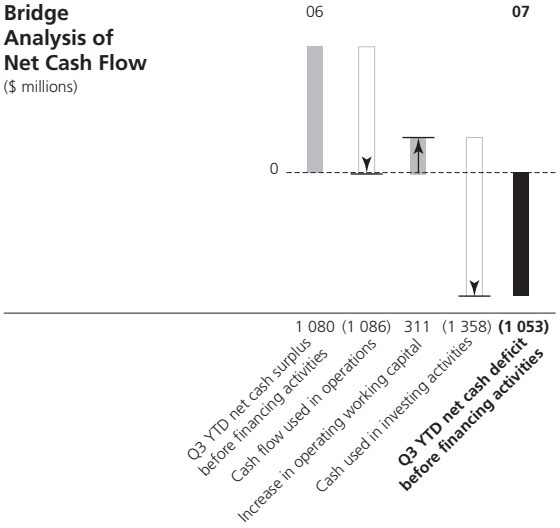
Net earnings for the first nine months of 2007 were $1.869 billion ($4.06 per common share), compared to $2.613 billion ($5.69 per common share) for the same period in 2006. Excluding the impacts of income tax rate revaluations, net insurance proceeds (relating to the January 2005 fire), unrealized foreign exchange gains on the company's U.S. dollar denominated long-term debt, and project start-up costs, earnings for the first nine months of 2007 were $1.640 billion ($3.56 per common share), compared to $1.972 billion ($4.30 per common share) in the same period for 2006. Earnings decreased as a result of increased maintenance and lower production during the first nine months of 2007, compared to the same period in 2006.

Cash flow from operations for the first nine months of 2007 was $2.701 billion, compared to $3.787 billion in the first nine months of 2006. Cash flow from operations was lower partially due to the same factors that impacted net earnings, as well as an increase in cash income tax expenses in the first nine months of 2007, compared to the first nine months of 2006.

Bridge Analysis of Net Earnings
($ millions)



Bridge Analysis of Net Cash Flow
($ millions)



Our effective tax rate for the first nine months of 2007 was 28%, compared to 33% in the first nine months of 2006. The lower effective tax rate in 2007 was due to a reduction in the federal income tax rate enacted in the second quarter of 2007 and the fully phased-in resource tax changes that resulted in Crown royalties becoming fully deductible and eliminated the resource allowance. During 2007, we expect our oil sands and refining and marketing businesses will become partially cash taxable. During the first nine months of 2007 we recorded $314 million in current income tax expense compared to a recovery of $11 million in the first nine months of 2006 (see page 8 for a more detailed discussion).

Net Earnings Components

This table explains certain 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 the accompanying notes prepared in accordance with Canadian GAAP.

	Three months ended September 30		Nine months ended September 30	
($ millions, after-tax)	**2007**	2006	**2007**	2006
Net earnings before the following items:	**588**	691	**1 640**	1 972
Unrealized foreign exchange gains on U.S. dollar denominated long-term debt	**108**	—	**199**	43
Impact of income tax rate reductions on opening future income tax liabilities	**—**	—	**67**	419
Oil sands fire accrued insurance proceeds [1]	**—**	—	**—**	205
Project start-up costs	**(19)**	(9)	**(37)**	(26)
Net earnings as reported	**677**	682	**1 869**	2 613

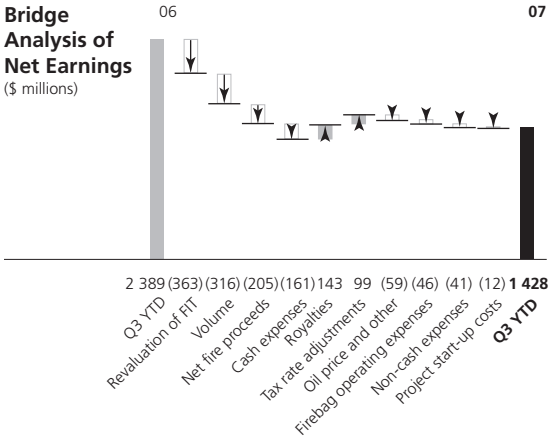
(1) Net accrued property loss and business interruption proceeds net of income taxes and Alberta Crown royalties.

Analysis of Segmented Earnings and Cash Flow

Oil Sands

Oil sands recorded 2007 third quarter net earnings of $556 million, compared with $582 million in the third quarter of 2006. Excluding the impact of project start-up costs, earnings for the third quarter of 2007 were $573 million, compared to $588 million in the third quarter of 2006. Earnings decreased primarily as a result of reduced sales volumes, an increase in depreciation, depletion and amortization, and higher royalty expenses. This was partially offset by higher average price realizations and a strong product mix for oil sands crude products during the third quarter of 2007. The increased price realization reflects higher benchmark WTI crude oil prices and the strengthening price differentials on our sweet and sour crude blends, partially offset by the increase in the value of the Canadian dollar.

Operating expenses were $515 million in the third quarter of 2007 compared to $509 million in the third quarter of 2006. The increase in operating expenses was primarily due to higher maintenance expenditures, in addition to an increase in stock-based compensation expense.



Transportation and other costs were $32 million in the third quarter of 2007, compared to $41 million in the third quarter of 2006. The decrease was due to reduced volumes shipped out of the Fort McMurray area.

Depreciation, depletion and amortization expense was $126 million in the third quarter of 2007, compared to $96 million during the same period in 2006. The increase resulted from continued growth in the depreciable cost base after the commissioning of new assets.

Alberta Crown royalty expense was $145 million in the third quarter of 2007, compared to $119 million in the third quarter of 2006. The increase was due mainly to higher current and future oil prices. See page 8 for a discussion of Alberta oil sands Crown royalties.

Project start-up costs for the third quarter of 2007 were $24 million, compared to $8 million in the third quarter of 2006. This increase was due primarily to initial start-up costs related to expansion work to increase production capacity to a targeted 350,000 bpd in 2008.

Cash flow from operations was $918 million in the third quarter of 2007, compared to $924 million in the third quarter of 2006. Cash flows were reduced by cash income taxes in the third quarter of 2007 that were largely absent in the third quarter of 2006. This impact was partially offset by the receipt of deferred revenues in the third quarter of 2007.

Net earnings for the first nine months of 2007 were $1.428 billion, compared to $2.389 billion in the first nine months of 2006. Cash flow from operations for the first nine months of 2007 decreased to $2.072 billion from $3.245 billion in the first nine months of 2006. The year-to-date decreases in net earnings and cash flow from operations were a result of lower sales volumes, a smaller income tax rate reduction in 2007, and the absence of net insurance proceeds (relating to the January 2005 fire) in the first nine months of 2007.

Oil sands production averaged 239,100 bpd in the third quarter of 2007. Production during the third quarter of 2006 averaged 242,800 bpd. Production was down as the result of a planned maintenance outage in July.

Sales volumes during the third quarter of 2007 averaged 223,900 bpd, compared with 238,000 bpd during the third quarter of 2006. The proportion of higher value diesel fuel and sweet crude products increased to 55% of total sales volumes in the third quarter of 2007, compared to 44% in the third quarter of 2006.

The average price realization for oil sands crude products increased to $76.97 per barrel in the third quarter of 2007, compared to $71.99 per barrel in the third quarter of 2006. A 7% increase in average benchmark WTI crude oil prices and the strengthening of our sweet and sour crude blends relative to WTI were partially offset by an 8% increase in the value of the Canadian dollar. Because crude oil is primarily sold based on U.S. dollar benchmark prices, a strengthening Canadian dollar produced a corresponding reduction in the Canadian dollar value of our products.

During the third quarter of 2007, cash operating costs averaged $25.10 per barrel, compared to $23.70 per barrel during the third quarter of 2006. The increase in cash operating costs per barrel was primarily due to higher maintenance costs and slightly lower production resulting from the planned outage. Refer to page 13 for further details on cash operating costs as a non-GAAP financial measure, including the calculation and reconciliation to GAAP measures.

Outlook

Unscheduled outages throughout the year have impacted year-to-date results at oil sands. As a result, management has revised its oil sands operation outlook, targeting an annual production average of 240,000 bpd to 245,000 bpd and cash operating costs of about $26.50 to $27.00 per barrel. The original outlook was an annual production average of 260,000 bpd to 270,000 bpd and cash operating costs of $21.50 to $22.50 per barrel.

Suncor is making progress to address challenges at its in-situ operation, where high emissions have resulted in intervention by both Alberta Environment and the Alberta Energy and Utilities Board. Until regulators can be assured emissions are stable at compliant levels, production at the in-situ operation has been capped at approximately 42,000 barrels of bitumen per day. As a result, commissioning of units to increase the bitumen production capacity of Firebag Stages 1 and 2 by about 35%, will be delayed. Suncor's revised outlook reflects this constraint.

To mitigate the impact to production, we are examining ways to increase bitumen supply from our mining operations. We are also accelerating the construction of emission abatement equipment, which will result in additional maintenance and capital costs being incurred.

An expansion project to increase production capacity to 350,000 bpd in the second half of 2008 is on schedule and on budget. Engineering is complete and construction is approximately 90% complete.

We remain on target for capital spending of approximately $3.5 billion this year on various components of our oil sands expansion.

For an update on our significant growth projects currently in progress see page 11.

Oil Sands Crown Royalties

On September 18, 2007, the Alberta Royalty Review Panel released its report recommending broad changes to the current royalty regime for both conventional and oil sands resource development. In its report, the panel recommends a significant increase in the royalty rate applicable to oil sands projects and the implementation of additional taxes. Although the government has indicated plans to make changes to the Alberta Crown Royalty regime in response to this report, we do not have sufficient information to determine the impact of changes the government may implement. Future royalties and taxes payable, as well as the determination of net mining and in-situ reserves, may be affected.

In the third quarter of 2007, we recorded a pretax royalty estimate of $145 million ($105 million after tax), compared to $119 million ($81 million after tax) for the third quarter of 2006.

We estimate 2007 annualized oil sands Crown royalties under current legislation to be approximately $600 million ($435 million after tax), compared to actual 2006 oil sands Crown royalties of $911 million ($619 million after tax). The decrease in the oil sands Crown royalties estimate is due primarily to an increase in allowable capital expenditures claimed and the absence of net insurance proceeds (relating to the January 2005 fire). This estimate is based on nine months of actual results and the balance of the year estimated on 2007 forward crude pricing of US$78.50 as at September 30, 2007, current forecasts of production, eligible capital and operating costs for the remainder of 2007, and a Cdn$/US$ foreign exchange rate of $1.01. Accordingly, actual results will differ, and these differences may be material.

Oil Sands Cash Income Taxes

We estimate we will incur cash taxes of approximately 50% to 70% of the expected 2007 provision for income tax expense. We do not anticipate any significant cash tax in subsequent years until approximately the middle of the next decade. In any year we may be subject to cash income tax due to sensitivity to crude oil and natural gas commodity price volatility, and the timing of recognition of capital expenditures for income tax purposes.

During the third quarter of 2007 oil sands recorded $45 million in current income tax expense, compared to $2 million in the comparative quarter in 2006.

The 2007 federal budget proposes to phase out the accelerated capital cost allowance that was originally intended to offset some of the risk associated with the large capital investment required to bring oil sands projects to production. The accelerated capital cost allowance will continue to be available for assets acquired before 2012 on major projects where major construction commenced before March 19, 2007. We believe Suncor's Voyageur expansion, targeted for completion in 2012, will fall under the current accelerated capital cost allowance provisions. Voyageur is expected to increase production capacity to 500,000 bpd to 550,000 bpd. Plans include the addition of a third upgrader, expansion to increase bitumen feedstock and the construction of related infrastructure. Construction of this multi-phased expansion project, including coke drum fabrication and site preparation, has begun (for details on capital spending in progress see page 11). Non-grandfathered oil sands capital will be eligible for the accelerated capital cost allowance as it is gradually phased out between 2011 and 2015 when the standard 25% declining balance rate applies.

Uncertainties and Sensitivities

The forward-looking information in the preceding "Oil Sands Crown Royalties" and "Oil Sands Cash Income Taxes" sections incorporates operating and capital cost assumptions included in our current budget and long-range plan, and is not an estimate, forecast or prediction of actual events or circumstances.

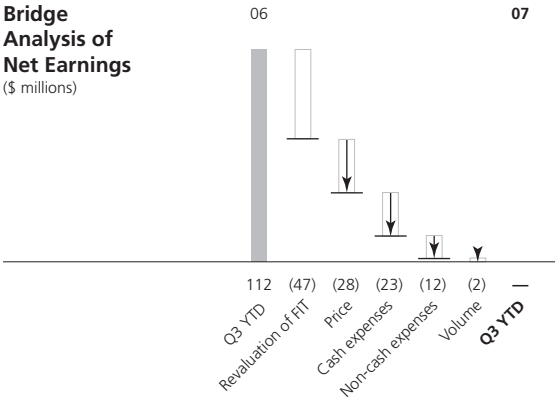
Anticipated royalty and cash taxes are highly sensitive to, among other factors, changes in crude oil and natural gas pricing, production volumes, foreign exchange rates, and capital and operating costs for each project. In addition, all aspects of the current Alberta oil sands Crown royalty regime (including royalty rates, the royalty base and the value of bitumen for royalty purposes), and income tax legislation (including taxation rates), are subject to alteration by the government.

In light of proposed legislative changes, other uncertainties, and the potential for unanticipated events, we strongly caution that it is impossible to accurately predict even a range of annualized royalty expense as a percentage of revenues or approximate cash tax, or the impact these royalties and cash taxes may have on our financial results. Differences may be material.

Natural Gas

Our natural gas business recorded net earnings of nil in the third quarter of 2007, compared with $12 million of net earnings during the third quarter of 2006. The decrease in net earnings was primarily the result of lower price realizations, higher depreciation, depletion and amortization costs, and higher lifting costs. These factors were partially offset by higher production volumes and lower exploration expense.

Bridge Analysis of Net Earnings
($ millions)



Cash flow from operations for the third quarter of 2007 was $47 million, compared to $68 million from the third quarter of 2006. The decrease is primarily due to the same factors affecting net earnings, excluding depreciation, depletion and amortization expenses.

Year-to-date net earnings were nil, compared to $112 million in the first nine months of 2006. The decrease in earnings is due mainly to a smaller income tax rate reduction in 2007 as well as lower price realizations and higher exploration, lifting, depreciation, depletion and amortization and transportation expenses.

Cash flow from operations for the first nine months of the year was $181 million, compared to $233 million reported in the same period in 2006. The year-to-date decrease in cash flow from operations was due to lower price realizations and higher transportation and lifting costs.

Natural gas and liquids production in the third quarter of 2007 was 211 million cubic feet equivalent (mmcfe) per day, compared to 208 mmcfe per day in the third quarter of 2006. Our 2007 production outlook targets an average of 215 to 220 mcfe per day for the year, offsetting Suncor's projected purchases for internal consumption at our oil sands operations.

Realized natural gas prices in the third quarter of 2007 were $5.39 per thousand cubic feet (mcf), compared to $6.33 per mcf in the third quarter of 2006, reflecting the lower benchmark commodity price.

Part of the Alberta Royalty Review Panel's report recommends changes to the current royalty regime for conventional oil and gas. Although the government has indicated plans to make changes to the Alberta Crown Royalty regime in response to this report, we do not have sufficient information to determine the impact of changes the government may implement. Future royalties and tax payable, as well as the determination of net conventional reserves, may be affected.

Refining and Marketing

Consistent with the company's organizational restructuring during the first quarter of 2007, results from our Canadian and U.S. downstream marketing and refining operations have been combined into a single business segment – Refining & Marketing. Comparative figures have been reclassified to reflect the combination of the previously disclosed Energy Marketing & Refining - Canada (EM&R) and Refining & Marketing – U.S.A. (R&M) segments. There was no impact to previously reported net earnings as a result of the combination. The results of company-wide energy marketing and trading will continue to be included in this segment. The financial results relating to the sales of oil sands and natural gas production will continue to be reported in their respective business segments.

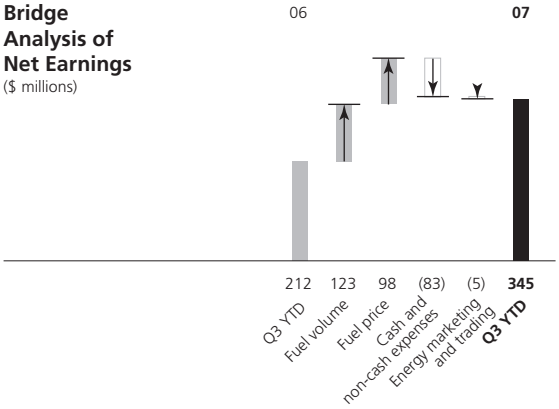
Our refining & marketing business recorded 2007 third quarter net earnings of $40 million, compared to net earnings of $85 million in the third quarter of 2006. Net earnings were lower due to reduced production capacity caused by the planned outage at our Sarnia, Ontario refinery which resulted in decreased production and increased product purchases to meet customer commitments. These negative impacts were partially offset by increased sales volumes at our Commerce City, Colorado refinery.

Energy marketing and trading activities, including physical trading activities, resulted in a net pretax gain of $1 million in the third quarter of 2007, compared to an $11 million pretax gain in the third quarter of 2006. See page 12 for further details on our energy marketing and trading activities.

Cash flow from operations was $83 million in the third quarter of 2007, compared to $162 million in the third quarter of 2006. This decrease reflects the impact of the same factors affecting net earnings.

During the third quarter of 2007, combined refinery crude oil utilization was 102%, compared to 95% in the third quarter of 2006. The higher utilization rate in the third quarter of 2007 was largely due to improved reliability

Bridge Analysis of Net Earnings
($ millions)



at our Commerce City refinery, partially offset by lower production at the Sarnia refinery due to the planned shutdown that began in September.

Net earnings for the first nine months of 2007 were $345 million, compared to $212 million during the first nine months of 2006. This increase, compared to the first nine months of 2006, reflects increased sales volumes and strong margins resulting from tight supply of refined products when operational issues lowered refinery utilizations.

Cash flow from operations for the first nine months of 2007 was $546 million, compared to $399 million in the first nine months of 2006. The increase in cash flows was primarily due to the same factors that affected net earnings.

Work continues on modifications to the Sarnia refinery that are expected to enable the facility to process up to 40,000 bpd of oil sands sour crude. A partial outage to tie-in new facilities, which began in early September, is expected to be completed in the fourth quarter of 2007.

Planned maintenance at portions of the Commerce City refinery is also underway, and is expected to conclude by the end of October. The refinery is expected to operate at reduced rates during the outage.

For an update on our significant growth projects currently in progress see page 11.

Corporate

During the first quarter of 2007, we began allocating stock-based compensation expense from the corporate segment to each of the reportable businesses. Comparative figures have been reclassified to reflect this change in presentation. There was no impact to consolidated net earnings as a result of the allocation.

Corporate recorded $81 million in net earnings in the third quarter of 2007, compared to net earnings of $3 million during the third quarter of 2006. Net earnings increased mainly due to the foreign exchange gains on our U.S dollar denominated long-term debt as a result of the continued strengthening of the Canadian dollar. After-tax unrealized foreign exchange gains on U.S. dollar denominated long-term debt were $108 million in the third quarter of 2007 compared to nil in the third quarter of 2006. The higher foreign exchange gains in 2007 were partially offset by an increase in stock-based compensation expense.

Cash used in operations was $21 million in the third quarter of 2007, compared to $1 million used in the third quarter of 2006. The increase in cash used in operations is primarily due to increased operating expenses.

Corporate had net earnings of $96 million in the first nine months of 2007, compared to a net loss of $100 million in the same period of 2006. Expenses decreased primarily due to the foreign exchange gains on our U.S dollar denominated long-term debt as a result of the continued strengthening of the Canadian dollar. Year-to-date 2007 after-tax unrealized foreign exchange gains on our U.S. dollar denominated debt were $199 million, compared to $43 million in 2006. Expenses were also higher in the comparative period of 2006 due to the impact of a large income tax revaluation on opening future income tax assets.

Cash used in operations was $98 million in the first nine months of 2007, compared to $90 million used in the first nine months of 2006. The increased use of cash in 2007 was due primarily to an increase in operating expenses partially offset by the absence of system implementation costs.

Breakdown of Net Corporate Earnings

Three months ended September 30 ($ millions)	**2007**	2006
Corporate earnings	**81**	3
Group eliminations	**—**	(13)
Total	**81**	(10)

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 $738 million at the end of the third quarter of 2007, compared to a surplus of $35 million at the end of the third quarter of 2006.

During the first nine months of 2007, net debt increased to approximately $2.8 billion from $1.8 billion at December 31, 2006. The increase in net debt levels was primarily a result of capital spending on our growth strategies.

In March, Suncor issued $600 million of 5.39% Medium Term Notes under an outstanding $2 billion debt shelf prospectus. In June, Suncor issued US$750 million of 6.50% Notes, and in September issued a further US$400 million of 6.50% Notes, both under an outstanding US$2 billion debt shelf prospectus. The proceeds of these issuances were used for general corporate purposes, including repayment of short-term borrowings, supporting Suncor's ongoing capital spending program and for working capital requirements.

At September 30, 2007 our undrawn credit facilities were approximately $1.9 billion. Outstanding debt shelf prospectuses filed in 2007 in Canada and the U.S. enable

the company to issue, subject to Board of Directors authorization, up to $1.4 billion in debt in Canada and US$850 million in debt in the US. We believe we have the capital resources from our undrawn credit facilities, cash flow from operations, and access to debt capital markets to fund the remainder of our 2007 capital spending program and to meet our current working capital requirements. If additional capital is required, we believe adequate additional financing will continue to be available at market terms and rates. As reported in our 2006 Annual Report, we anticipate capital spending of approximately $5.3 billion for 2007.

Significant Capital Project Update

A summary of the progress on our significant projects under construction is provided below. All projects listed below have received Board of Directors approval.

Description	Cost Estimate (1) ($ millions)	Spent 2007 Year-to-date ($ millions)	Total spent to date ($ millions)	Status (1)
Oil Sands				
Coker unit	$2 100	$445	$2 035	Project is on schedule and on budget.
Naphtha unit (2)	$650	$190	$275	Project is on schedule and on budget.
Steepbank extraction plant (3)	$880	$200	$265	Project is on schedule and on budget.
Firebag cogeneration and expansion	$400	$65	$380	Project is mechanically complete.(4)
Refining and Marketing				
Diesel desulphurization and oil sands integration	$960	$95	$895	Diesel desulphurization component complete. Oil sands integration component is scheduled for completion in Q4 2007. (5)

(1) Estimating and budgeting for major capital projects is a process that involves uncertainties and that evolves in stages, each with progressively more refined data and a correspondingly narrower range of uncertainty. At very early stages, when broad engineering design specifications are developed, the level of uncertainty can result in price ranges with -30%/+50% (or similar) levels of uncertainty. As project engineering progresses, vendor bids are studied, goods and materials ordered and we move closer to the build stage, the level of uncertainty narrows. Generally, when projects receive final approval from our Board of Directors, our cost estimates have a range of uncertainty that has narrowed to the -10%/+10% or similar range. These ranges establish an expected high and low capital cost estimate for a project. When we say that a project is "on budget", we mean that we still expect the final project capital cost to fall within the current range of uncertainty for the project. Even at this stage, the uncertainties in the estimating process and the impact of future events, can and will cause actual results to differ, in some cases materially, from our estimates. Cost estimates do not include commissioning and start-up expenses.

(2) The naphtha unit is expected to enhance the product mix of our oil sands production.

(3) The Steepbank extraction plant is intended to replace and enhance existing base plant extraction facilities.

(4) Cogeneration is operational, however commissioning of the units required to complete the expansion of bitumen production by about 35% has been delayed. See page 7 for discussion.

(5) See page 9 for discussion.

Key components of the multi-phased Voyageur growth strategy are still pending approval from regulators and Suncor's Board of Directors. As a result, Suncor has not yet announced a firm capital cost estimate for its planned third upgrader and expansions to increase bitumen supply, which include the addition of future stages of the Firebag in-situ operation.

However, engineering for these projects is underway and advance construction is in progress. To date, approximately $900 million has been approved for preparatory work related to the third upgrader, including engineering, site preparation and fabrication of major vessels. Approximately $1.4 billion in capital spending has also been approved to date by the Board of Directors for future expansions at Firebag.

Approval to proceed with these projects will be considered by Suncor's Board of Directors once final cost estimates are complete. Preliminary cost estimates, including those provided in Suncor's Voyageur regulatory approval application, have a wide range of uncertainty and are under upward pressure.

Derivative Financial Instruments

Effective January 1, 2007, new accounting standards were implemented relating to financial instruments. For a more detailed discussion, see Change in Accounting Policies on page 13. These changes did not significantly impact earnings as a result of the adoption.

The company has hedged a portion of its forecasted Canadian and U.S. dollar denominated cash flows subject to U.S. dollar West Texas Intermediate (WTI) commodity price risk for 2007 and 2008. At September 30, 2007, costless collar crude oil hedges totaling 60,000 bpd of production were outstanding for the remainder of 2007 and 10,000 bpd for 2008. Prices for these barrels are fixed within a range from an average of US$51.64/bbl up to an average of US$101.06/bbl.

We intend to consider additional costless collars of up to approximately 30% of our annual planned crude oil production if strategic opportunities are available.

We had no hedging gains or losses from our crude oil hedges in the third quarter of 2007, and $2 million of hedging gains from our crude oil hedges in the first nine months of 2007. There were no crude oil hedging gains in the first nine months of 2006.

The fair value of strategic derivative hedging instruments is the estimated amount, based on brokers' quotes and/or internal valuation models, the company would receive (pay) to terminate the contracts. In addition to our strategic hedging program, we also use derivative instruments to hedge risks specific to individual transactions. Such amounts, which also represent the unrecognized and unrecorded gain (loss), on the contracts, were as follows at September 30:

Fair Value of Hedging Derivative Financial Instruments

($ millions)	**2007**	2006
Revenue hedge swaps and collars	**—**	14
Fixed to float interest rate swaps	**6**	13
Specific cash flow hedges of individual transactions	**6**	(3)
Total	**12**	24

Energy Marketing and Trading Activities

The net pretax earnings (loss) for the three and nine months ended September 30, were as follows:

Net Pretax Earnings (Loss)

	Three months ended September 30		Nine months ended September 30	
($ millions)	**2007**	2006	**2007**	2006
Physical energy contracts trading activity	**5**	14	**26**	30
Financial energy contracts trading activity	**(3)**	(2)	**(7)**	(3)
General and administrative costs	**(1)**	(1)	**(2)**	(2)
Total	**1**	11	**17**	25

The fair value of unsettled (unrealized) financial energy trading assets and liabilities at September 30, 2007 and December 31, 2006 are as follows:

Fair Value of Unsettled (Unrealized) Financial Energy Trading Assets and Liabilities

($ millions)	**2007**	2006
Energy trading assets	**2**	16
Energy trading liabilities	**13**	13
Net trading assets (liabilities)	**(11)**	3

Greenhouse Gas Regulation and Risk

On March 8, 2007 the Alberta government introduced the Climate Change and Emissions Management Amendment Act, which places intensity (emissions per unit of production) limits on facilities emitting more than 100,000 tonnes of carbon dioxide equivalent per year. Suncor's oil sands operations are subject to this legislation. The act calls for intensity reductions of 12% from an average 2003 to 2005 baseline, by July 1, 2007.

To comply with this new legislation, Suncor must, by the end of 2007, determine and file baseline emission data with regulators. In March 2008, compliance with the legislation will commence. Mitigation options available to Suncor include internal emission reductions, utilizing offset projects or contributing to a climate change emission management fund.

The actual costs to Suncor will be dependent on a variety of factors that are not yet certain, including baseline calculation, facilities definition and potential offset credits. However, Suncor is currently accruing $0.10/bbl which reflects our estimated cost of compliance.

The Ontario provincial, Colorado state and Canadian federal governments are also in various stages of developing greenhouse gas management legislation and regulation. At this time, no such legislation has been tabled in any of these jurisdictions and any potential impacts are unknown.

While there remains uncertainty around the outcome and impacts of climate change regulation, we continue to actively manage our emissions and to pursue opportunities such as carbon capture and sequestration and renewable energy development.

Control Environment

Based on their evaluation as of September 30, 2007, 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 and 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, 2007, there were no changes in our internal control over financial reporting that occurred during the three month period ended September 30, 2007 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

On January 1, 2007 the company adopted CICA Handbook Section 3855 "Financial Instruments, Recognition and Measurement", Section 1530 "Comprehensive Income" and Section 3865 "Hedging". These sections establish the accounting and reporting standards for financial instruments and hedging activities, and require the initial recognition of financial instruments at fair value on the balance sheet. The comparative interim consolidated financial statements have not been restated, except for the presentation of the cumulative foreign currency translation adjustment.

Transaction costs and the related cash flow impacts are included in the fair value assessments of each financial asset and financial liability instrument.

Generally, all derivatives, whether designated in hedging relationships or not, excluding those considered as normal purchases and normal sales, are required to be recorded on the balance sheet at fair value. If the derivative is designated as a fair value hedge, changes in the fair value of the derivative and changes in the fair value of the hedged item attributable to the hedged risk each period are recognized in the Consolidated Statements of Earnings. If the derivative is designated as a cash flow hedge, the effective portions of the changes in fair value of the derivative are initially recorded in other comprehensive income each period and are recognized in the Consolidated Statements of Earnings when the hedged item is recognized. Ineffective portions of changes in the fair value of hedging instruments are recognized in the Consolidated Statements of Earnings immediately for both fair value and cash flow hedges.

Gains or losses arising from hedging activities, including the ineffective portion, are reported in the same Consolidated Statements of Earnings caption as the hedged item. The determination of hedge effectiveness and the measurement of hedge ineffectiveness for cash flow hedges are based on internally derived valuations. The company uses these valuations to estimate the fair values of the underlying physical commodity contracts.

In addition to containing the effective portions of the gains/losses on our cash flow hedges, the accumulated other comprehensive income account will also contain the cumulative foreign currency translation adjustment of our foreign operations.

Upon implementation and initial measurement under the new standards at January 1, 2007, the following adjustments were recorded to the balance sheet:

Financial assets	$42 million
Financial liabilities	$29 million
Retained earnings	$5 million
Accumulated other comprehensive loss	$63 million

The comparative interim consolidated financial statements have not been restated, except for presentation of the foreign currency translation adjustment of $71 million.

Non-GAAP Financial Measures

Certain financial measures referred to in this MD&A, namely cash flow from operations, return on capital employed (ROCE) and oil sands cash and total operating costs per barrel, are not prescribed by GAAP. These non-GAAP financial measures do not have any standardized meaning and therefore are unlikely to be comparable to similar measures presented by other companies. Suncor includes these non-GAAP financial measures because

investors may use this information to analyze operating performance, leverage and liquidity. The additional information should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP.

Suncor provides a detailed numerical reconciliation of ROCE on an annual basis in the company's annual MD&A, which is to be read in conjunction with the company's annual consolidated financial statements. For a summarized narrative reconciliation of ROCE calculated on a September 30, 2007 interim basis, please refer to page 33.

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, 2007 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	
		2007	2006	**2007**	2006
Cash flow from operations ($ millions)	A	**1 027**	1 153	**2 701**	3 787
Weighted-average number of shares outstanding (millions of shares)	B	**461.5**	459.4	**460.8**	458.9
Cash flow from operations ($ per share)	(A/B)	**2.23**	2.51	**5.86**	8.25

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			
		2007		2006		**2007**		2006	
		$ millions	$/barrel	$ millions	$/barrel	$ millions	$/barrel	$ millions	$/barrel
Operating, selling and general expenses		**515**		509		**1 783**		1 502	
Less: natural gas costs, inventory changes and stock-based compensation		**(17)**		(31)		**(257)**		(227)	
Less: non-monetary transactions		**(17)**		(25)		**(80)**		(104)	
Accretion of asset retirement obligations		**10**		7		**30**		21	
Taxes other than income taxes		**15**		9		**39**		28	
Cash costs		**506**	**23.00**	469	21.00	**1 515**	**24.15**	1 220	17.30
Natural gas		**46**	**2.10**	58	2.60	**223**	**3.55**	202	2.85
Imported bitumen (net of other reported product purchases)		**—**	**—**	3	0.10	**3**	**0.05**	6	0.10
Total cash operating costs	A	**552**	**25.10**	530	23.70	**1 741**	**27.75**	1 428	20.25
Project start-up costs	B	**24**	**1.10**	8	0.35	**47**	**0.75**	32	0.45
Total cash operating costs after start-up costs	A+B	**576**	**26.20**	538	24.05	**1 788**	**28.50**	1 460	20.70
Depreciation, depletion and amortization		**126**	**5.70**	96	4.30	**334**	**5.30**	281	4.00
Total operating costs		**702**	**31.90**	634	28.35	**2 122**	**33.80**	1 741	24.70
Production (thousands of barrels per day)		**239.1**		242.8		**229.8**		258.1	

Oil Sands Operating Costs – In-situ Bitumen Production Only

	Three months ended September 30				Nine months ended September 30			
	2007		2006		**2007**		2006	
	$ millions	$/barrel	$ millions	$/barrel	$ millions	$/barrel	$ millions	$/barrel
Operating, selling and general expenses	**67**		44		**204**		128	
Less: natural gas costs and inventory changes	**(30)**		(26)		**(100)**		(71)	
Taxes other than income taxes	**2**		1		**5**		3	
Cash costs	**39**	**11.85**	19	5.55	**109**	**11.15**	60	6.60
Natural gas	**30**	**9.10**	26	7.60	**100**	**10.25**	71	7.80
Cash operating costs	**69**	**20.95**	45	13.15	**209**	**21.40**	131	14.40
In-situ (Firebag) start-up costs	**—**	**—**	—	—	**—**	**—**	21	2.30
Total cash operating costs	**69**	**20.95**	45	13.15	**209**	**21.40**	152	16.70
Depreciation, depletion and amortization	**22**	**6.70**	19	5.55	**58**	**5.95**	48	5.30
Total operating costs	**91**	**27.65**	64	18.70	**267**	**27.35**	200	22.00
Production (thousands of barrels per day)	**35.8**		37.2		**35.8**		33.3	

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," "indicates," "could," "focus," "goal," "proposed," "target," "objective," "may," "outlook," "on our way,' "looking forward," "investigating," "continue," 'strategy," 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 include but are not limited to changes in the general economic, market and business conditions; fluctuations in supply and demand for Suncor's products; commodity prices 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 Firebag in-situ development and Voyageur) and regulatory projects; 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; 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; 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 current review of the Crown Royalty regime, the Government of Canada's current review of greenhouse gas emission regulations and the issuance of the September 21, 2007 Alberta Environment order and the September 24, 2007 EUB directive); 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 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 2007	Third quarter 2006	Nine months ended Sept 30 2007	Nine months ended Sept 30 2006
Revenues (note 4)	**4 666**	4 114	**12 975**	12 042
Expenses				
Purchases of crude oil and products	**1 733**	1 472	**4 389**	3 656
Operating, selling and general (notes 4 and 7)	**722**	656	**2 454**	2 082
Energy marketing and trading activities (note 4)	**746**	427	**1 927**	1 043
Transportation and other costs	**49**	54	**144**	152
Depreciation, depletion and amortization	**216**	180	**610**	504
Accretion of asset retirement obligations	**12**	9	**36**	26
Exploration	**9**	18	**78**	80
Royalties (note 11)	**170**	143	**490**	771
Taxes other than income taxes	**165**	156	**487**	438
Gain on disposal of assets	**(1)**	(2)	**—**	(5)
Project start-up costs	**26**	13	**52**	39
Financing income (note 5)	**(100)**	—	**(185)**	(13)
	3 747	3 126	**10 482**	8 773
Earnings Before Income Taxes	**919**	988	**2 493**	3 269
Provision for (Recovery of) Income Taxes (note 10)				
Current	**69**	(2)	**314**	(11)
Future	**173**	308	**310**	667
	242	306	**624**	656
Net Earnings	**677**	682	**1 869**	2 613
Other comprehensive loss, net of income taxes	**(76)**	—	**(170)**	(36)
Comprehensive income	**601**	682	**1 699**	2 577
Net Earnings Per Common Share (dollars), (note 6)				
Basic	**1.47**	1.48	**4.06**	5.69
Diluted	**1.43**	1.45	**3.97**	5.56
Cash dividends	**0.10**	0.08	**0.24**	0.22

See accompanying notes.

Consolidated balance sheets

(unaudited)

($ millions)	**September 30 2007**	December 31 2006 (restated) (note 2)
Assets		
Current assets		
Cash and cash equivalents	**716**	521
Accounts receivable (notes 2 and 4)	**1 254**	1 050
Inventories	**674**	589
Income taxes receivable	**97**	33
Future income taxes	**112**	109
Total current assets	**2 853**	2 302
Property, plant and equipment, net	**19 276**	16 160
Deferred charges and other (notes 2 and 4)	**367**	297
Total assets	**22 496**	18 759
Liabilities and Shareholders' Equity		
Current liabilities		
Short-term debt	**5**	7
Accounts payable and accrued liabilities (notes 2, 4 and 11)	**2 507**	2 111
Taxes other than income taxes	**53**	40
Income taxes payable	**203**	—
Total current liabilities	**2 768**	2 158
Long-term debt (note 12)	**3 468**	2 363
Accrued liabilities and other (notes 2 and 4)	**1 230**	1 214
Future income taxes (notes 2, 4 and 10)	**4 378**	4 072
Shareholders' equity (see below)	**10 652**	8 952
Total liabilities and shareholders' equity	**22 496**	18 759

Shareholders' Equity

	Number (thousands)		Number (thousands)	
Share capital	**461 941**	**856**	459 944	794
Contributed surplus		**155**		100
Accumulated other comprehensive income (notes 2 and 4)		**(233)**		(71)
Retained earnings (note 2)		**9 874**		8 129
Total shareholders' equity		**10 652**		8 952

See accompanying notes.

Consolidated statements of cash flows

(unaudited)

($ millions)	Third quarter 2007	Third quarter 2006	Nine months ended September 30 2007	Nine months ended September 30 2006
Operating Activities				
Cash flow from operations	**1 027**	1 153	**2 701**	3 787
Decrease (increase) in operating working capital				
Accounts receivable	**(125)**	49	**(197)**	(100)
Inventories	**(51)**	(98)	**(85)**	(125)
Accounts payable and accrued liabilities	**(176)**	219	**54**	(147)
Taxes payable/receivable	**(55)**	(38)	**152**	(15)
Cash flow from operating activities	**620**	1 285	**2 625**	3 400
Cash Used in Investing Activities	**(1 256)**	(866)	**(3 678)**	(2 320)
Net Cash Surplus (Deficiency) Before Financing Activities	**(636)**	419	**(1 053)**	1 080
Financing Activities				
Decrease in short-term debt	**(1)**	—	**(2)**	(41)
Net proceeds from issuance of long-term debt	**428**	—	**1 835**	—
Net increase (decrease) in long-term debt	**18**	(270)	**(469)**	(886)
Issuance of common shares under stock option plan	**16**	7	**44**	40
Dividends paid on common shares	**(42)**	(34)	**(120)**	(92)
Deferred revenue	**1**	11	**4**	27
Cash provided by (used in) financing activities	**420**	(286)	**1 292**	(952)
Increase (Decrease) in Cash and Cash Equivalents	**(216)**	133	**239**	128
Effect of Foreign Exchange on Cash and Cash Equivalents	**(20)**	(1)	**(44)**	(3)
Cash and Cash Equivalents at Beginning of Period	**952**	158	**521**	165
Cash and Cash Equivalents at End of Period	**716**	290	**716**	290

See accompanying notes.

Consolidated statements of changes in shareholders' equity

(unaudited)

($ millions)	Share Capital	Contributed Surplus	Cumulative Foreign Currency Translation	Retained Earnings	Accumulated Other Comprehensive Income (AOCI)
At December 31, 2005, as previously reported	732	50	(81)	5 295	—
Retroactive adjustment for change in accounting policy (note 2)	—	—	81	—	(81)
At December 31, 2005, as restated	732	50	—	5 295	(81)
Net earnings	—	—	—	2 613	—
Dividends paid on common shares	—	—	—	(92)	—
Issued for cash under stock option plan	45	(5)	—	—	—
Issued under dividend reinvestment plan	7	—	—	(7)	—
Stock-based compensation expense	—	31	—	—	—
Change in AOCI related to foreign currency translation	—	—	—	—	(36)
At September 30, 2006	784	76	—	7 809	(117)
At December 31, 2006, as previously reported	794	100	(71)	8 129	—
Retroactive adjustment for change in accounting policy (note 2)	—	—	71	—	(71)
At December 31, 2006, as restated	794	100	—	8 129	(71)
Net earnings	**—**	**—**	**—**	**1 869**	**—**
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	**856**	**155**	**—**	**9 874**	**(233)**

See accompanying notes.

Schedules of segmented data

(unaudited)

									Third quarter	
	Oil Sands		Natural Gas		Refining and Marketing (note 3)		Corporate and Eliminations		Total	
($ millions)	**2007**	2006	**2007**	2006	**2007**	2006	**2007**	2006	**2007**	2006
EARNINGS										
Revenues										
Operating revenues	**1 618**	1 573	**120**	126	**2 169**	1 971	**1**	2	**3 908**	3 672
Energy marketing and trading activities	**—**	—	**—**	—	**771**	440	**(23)**	(2)	**748**	438
Intersegment revenues	**94**	135	**1**	6	**—**	—	**(95)**	(141)	**—**	—
Interest	**—**	—	**—**	1	**—**	2	**10**	1	**10**	4
	1 712	1 708	**121**	133	**2 940**	2 413	**(107)**	(140)	**4 666**	4 114
Expenses										
Purchases of crude oil and products	**68**	71	**—**	—	**1 758**	1 524	**(93)**	(123)	**1 733**	1 472
Operating, selling and general (note 3)	**515**	509	**32**	29	**160**	139	**15**	(21)	**722**	656
Energy marketing and trading activities	**—**	—	**—**	—	**770**	429	**(24)**	(2)	**746**	427
Transportation and other costs	**32**	41	**9**	6	**8**	7	**—**	—	**49**	54
Depreciation, depletion and amortization	**126**	96	**43**	38	**38**	40	**9**	6	**216**	180
Accretion of asset retirement obligations	**10**	7	**2**	1	**—**	1	**—**	—	**12**	9
Exploration	**—**	—	**9**	18	**—**	—	**—**	—	**9**	18
Royalties (note 11)	**145**	119	**25**	24	**—**	—	**—**	—	**170**	143
Taxes other than income taxes	**24**	17	**1**	1	**140**	137	**—**	1	**165**	156
Gain on disposal of assets	**—**	—	**(1)**	(1)	**—**	(1)	**—**	—	**(1)**	(2)
Project start-up costs	**24**	8	**—**	—	**2**	5	**—**	—	**26**	13
Financing income	**—**	—	**—**	—	**—**	—	**(100)**	—	**(100)**	—
	944	868	**120**	116	**2 876**	2 281	**(193)**	(139)	**3 747**	3 126
Earnings (loss) before income taxes	**768**	840	**1**	17	**64**	132	**86**	(1)	**919**	988
Income taxes	**(212)**	(258)	**(1)**	(5)	**(24)**	(47)	**(5)**	4	**(242)**	(306)
Net earnings (loss)	**556**	582	**—**	12	**40**	85	**81**	3	**677**	682

Schedules of segmented data (continued)

(unaudited)

									Third quarter	
	Oil Sands		Natural Gas		Refining and Marketing (note 3)		Corporate and Eliminations		Total	
($ millions)	**2007**	2006	**2007**	2006	**2007**	2006	**2007**	2006	**2007**	2006
CASH FLOW BEFORE FINANCING ACTIVITIES										
Cash flow from (used in) operating activities:										
Cash flow from (used in) operations										
Net earnings	**556**	582	**—**	12	**40**	85	**81**	3	**677**	682
Exploration expenses	**—**	—	**2**	15	**—**	—	**—**	—	**2**	15
Non-cash items included in earnings										
Depreciation, depletion and amortization	**126**	96	**43**	38	**38**	40	**9**	6	**216**	180
Future income taxes	**167**	256	**—**	5	**(1)**	40	**7**	7	**173**	308
Gain on disposal of assets	**—**	—	**(1)**	(1)	**—**	(1)	**—**	—	**(1)**	(2)
Stock-based compensation expense	**12**	5	**1**	—	**7**	3	**4**	4	**24**	12
Other	**—**	(10)	**2**	(1)	**—**	(6)	**(122)**	(5)	**(120)**	(22)
Increase (decrease) in deferred credits and other	**57**	(5)	**—**	—	**(1)**	1	**—**	(16)	**56**	(20)
Total cash flow from (used in) operations	**918**	924	**47**	68	**83**	162	**(21)**	(1)	**1 027**	1 153
Decrease (increase) in operating working capital	**(14)**	(73)	**1**	35	**(126)**	(1)	**(268)**	171	**(407)**	132
Total cash flow from (used in) operating activities	**904**	851	**48**	103	**(43)**	161	**(289)**	170	**620**	1 285
Cash from (used in) investing activities:										
Capital and exploration expenditures	**(1 227)**	(585)	**(67)**	(99)	**(101)**	(102)	**(22)**	(9)	**(1 417)**	(795)
Deferred maintenance shutdown expenditures	**(42)**	—	**—**	—	**(16)**	(4)	**—**	—	**(58)**	(4)
Deferred outlays and other investments	**—**	—	**—**	—	**2**	2	**(16)**	(12)	**(14)**	(10)
Proceeds from disposals	**—**	1	**5**	(1)	**—**	—	**—**	—	**5**	—
Decrease (increase) in investing working capital	**224**	(29)	**—**	—	**4**	(28)	**—**	—	**228**	(57)
Total cash (used in) investing activities	**(1 045)**	(613)	**(62)**	(100)	**(111)**	(132)	**(38)**	(21)	**(1 256)**	(866)
Net cash surplus (deficiency) before financing activities	**(141)**	238	**(14)**	3	**(154)**	29	**(327)**	149	**(636)**	419

Schedules of segmented data (continued)

(unaudited)

									Nine months ended September 30	
	Oil Sands		Natural Gas		Refining and Marketing (note 3)		Corporate and Eliminations		Total	
($ millions)	**2007**	2006	**2007**	2006	**2007**	2006	**2007**	2006	**2007**	2006
EARNINGS										
Revenues										
Operating revenues	**4 395**	4 765	**400**	420	**6 206**	5 387	**4**	4	**11 005**	10 576
Energy marketing and trading activities	**—**	—	**—**	—	**1 971**	1 097	**(25)**	(25)	**1 946**	1 072
Net insurance proceeds	**—**	385	**—**	—	**—**	—	**—**	—	**—**	385
Intersegment revenues	**388**	581	**9**	23	**—**	—	**(397)**	(604)	**—**	—
Interest	**—**	—	**—**	1	**4**	3	**20**	5	**24**	9
	4 783	5 731	**409**	444	**8 181**	6 487	**(398)**	(620)	**12 975**	12 042
Expenses										
Purchases of crude oil and products	**137**	88	**—**	—	**4 627**	4 146	**(375)**	(578)	**4 389**	3 656
Operating, selling and general (note 3)	**1 783**	1 502	**102**	82	**511**	456	**58**	42	**2 454**	2 082
Energy marketing and trading activities	**—**	—	**—**	—	**1 954**	1 072	**(27)**	(29)	**1 927**	1 043
Transportation and other costs	**96**	114	**25**	17	**23**	21	**—**	—	**144**	152
Depreciation, depletion and amortization	**334**	281	**128**	110	**117**	94	**31**	19	**610**	504
Accretion of asset retirement obligations	**30**	21	**5**	4	**1**	1	**—**	—	**36**	26
Exploration	**13**	22	**65**	58	**—**	—	**—**	—	**78**	80
Royalties (note 11)	**401**	682	**89**	89	**—**	—	**—**	—	**490**	771
Taxes other than income taxes	**65**	58	**4**	3	**417**	376	**1**	1	**487**	438
Loss (gain) on disposal of assets	**—**	—	**(1)**	(5)	**1**	—	**—**	—	**—**	(5)
Project start-up costs	**47**	32	**—**	—	**5**	7	**—**	—	**52**	39
Financing income	**—**	—	**—**	—	**—**	—	**(185)**	(13)	**(185)**	(13)
	2 906	2 800	**417**	358	**7 656**	6 173	**(497)**	(558)	**10 482**	8 773
Earnings (loss) before income taxes	**1 877**	2 931	**(8)**	86	**525**	314	**99**	(62)	**2 493**	3 269
Income taxes	**(449)**	(542)	**8**	26	**(180)**	(102)	**(3)**	(38)	**(624)**	(656)
Net earnings (loss)	**1 428**	2 389	**—**	112	**345**	212	**96**	(100)	**1 869**	2 613
As at September 30										
TOTAL ASSETS	**16 698**	12 933	**1 724**	1 370	**4 269**	4 012	**(195)**	(993)	**22 496**	17 322

Schedules of segmented data (continued)

(unaudited)

									Nine months ended September 30	
	Oil Sands		Natural Gas		Refining and Marketing (note 3)		Corporate and Eliminations		Total	
($ millions)	**2007**	2006	**2007**	2006	**2007**	2006	**2007**	2006	**2007**	2006
CASH FLOW BEFORE FINANCING ACTIVITIES										
Cash flow from (used in) operating activities:										
Cash flow from (used in) operations										
Net earnings (loss)	**1 428**	2 389	**—**	112	**345**	212	**96**	(100)	**1 869**	2 613
Exploration expenses	**—**	—	**54**	40	**—**	—	**—**	—	**54**	40
Non-cash items included in earnings										
Depreciation, depletion and amortization	**334**	281	**128**	110	**117**	94	**31**	19	**610**	504
Future income taxes	**248**	553	**(8)**	(26)	**72**	83	**(2)**	57	**310**	667
Loss (gain) on disposal of assets	**—**	—	**(1)**	(5)	**1**	—	**—**	—	**—**	(5)
Stock-based compensation expense	**30**	14	**3**	1	**15**	8	**14**	8	**62**	31
Other	**(13)**	24	**6**	1	**—**	4	**(237)**	(59)	**(244)**	(30)
Increase (decrease) in deferred credits and other	**45**	(16)	**(1)**	—	**(4)**	(2)	**—**	(15)	**40**	(33)
Total cash flow from (used in) operations	**2 072**	3 245	**181**	233	**546**	399	**(98)**	(90)	**2 701**	3 787
Decrease (increase) in operating working capital	**436**	(295)	**12**	(6)	**(137)**	(45)	**(387)**	(41)	**(76)**	(387)
Total cash flow from (used in) operating activities	**2 508**	2 950	**193**	227	**409**	354	**(485)**	(131)	**2 625**	3 400
Cash from (used in) investing activities:										
Capital and exploration expenditures	**(3 138)**	(1 547)	**(425)**	(341)	**(224)**	(501)	**(42)**	(23)	**(3 829)**	(2 412)
Deferred maintenance shutdown expenditures	**(98)**	—	**(1)**	—	**(28)**	(56)	**—**	—	**(127)**	(56)
Deferred outlays and other investments	**1**	(2)	**—**	—	**—**	7	**(16)**	(5)	**(15)**	—
Proceeds from disposals	**—**	1	**5**	13	**1**	3	**—**	—	**6**	17
Proceeds from property loss	**—**	29	**—**	—	**—**	—	**—**	—	**—**	29
Decrease (increase) in investing working capital	**314**	154	**—**	—	**(27)**	(52)	**—**	—	**287**	102
Total cash (used in) investing activities	**(2 921)**	(1 365)	**(421)**	(328)	**(278)**	(599)	**(58)**	(28)	**(3 678)**	(2 320)
Net cash surplus (deficiency) before financing activities	**(413)**	1 585	**(228)**	(101)	**131**	(245)	**(543)**	(159)	**(1 053)**	1 080

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 and note 3, Change in Segmented Disclosures.

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, 2007 and the results of its operations and cash flows for the three and nine month periods ended September 30, 2007 and 2006.

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

2. CHANGES IN ACCOUNTING POLICIES

Financial Instruments

On January 1, 2007 the company adopted CICA Handbook Section 3855 "Financial Instruments, Recognition and Measurement", Section 1530 "Comprehensive Income" and Section 3865 "Hedging". These sections establish the accounting and reporting standards for financial instruments and hedging activities, and require the initial recognition of financial instruments at fair value on the balance sheet.

Transaction costs and the related cash flow impacts are included in the fair value assessments of each financial asset and financial liability instrument.

Generally, all derivatives, whether designated in hedging relationships or not, excluding those considered as normal purchases and normal sales, are required to be recorded on the balance sheet at fair value. If the derivative is designated as a fair value hedge each period, changes in the fair value of the derivative and changes in the fair value of the hedged item attributable to the hedged risk are recognized in the Consolidated Statements of Earnings. If the derivative is designated as a cash flow hedge each period, the effective portions of the changes in fair value of the derivative are initially recorded in other comprehensive income and are recognized in the Consolidated Statements of Earnings when the hedged item is recognized. Ineffective portions of changes in the fair value of hedging instruments are recognized in the Consolidated Statements of Earnings immediately for both fair value and cash flow hedges.

Gains or losses arising from hedging activities, including the ineffective portion, are reported in the same Consolidated Statement of Earnings caption as the hedged item. The determination of hedge effectiveness and the measurement of hedge ineffectiveness for cash flow hedges are based on internally derived valuations. The company uses these valuations to estimate the fair values of the underlying physical commodity contracts.

In addition to containing the effective portions of the gains/losses on our cash flow hedges, the accumulated other comprehensive income account will also contain the cumulative foreign currency translation adjustment of our foreign operations.

Upon implementation and initial measurement under the new standards at January 1, 2007, the following adjustments were recorded to the balance sheet:

Financial Assets	$42 million
Financial Liabilities	$29 million
Retained Earnings	$5 million
Accumulated Other Comprehensive Loss	$63 million

The comparative interim consolidated financial statements have not been restated, except for the presentation of the cumulative foreign currency translation adjustment of $71 million.

Additional disclosure requirements for financial instruments have been approved by the CICA, and will be required disclosure for the company beginning January 1, 2008.

See Note 4 for a summary of financial instrument disclosures at September 30, 2007.

3. CHANGE IN SEGMENTED DISCLOSURES

Consistent with the company's organizational restructuring during the first quarter of 2007, results from our Canadian and U.S. downstream refining and marketing operations have been combined into a single business segment – Refining & Marketing. Comparative figures have been reclassified to reflect the combination of the previously disclosed Energy Marketing & Refining – Canada (EM&R) and Refining & Marketing – U.S.A. (R&M) segments. The results of company-wide energy marketing and trading activities will continue to be included in this segment. The financial results relating to the sales of oil sands and natural gas production will continue to be reported in their respective business segments. There was no impact to consolidated net earnings as a result of the restructuring.

Effective January 1, 2007, the company began allocating stock-based compensation expense to each of the reportable business segments. Comparative figures have been reclassified to reflect the allocation of stock-based compensation. There was no impact to consolidated net earnings as a result of the allocation.

4. FINANCIAL INSTRUMENTS

Balance Sheet Financial Instruments

The company's financial instruments recognized in the Consolidated Balance Sheet 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, or through comparisons to similar debt instruments; 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 with the exception of the portion of debt that has related financial hedges which is accounted for under the fair value hedge methodology outlined below. 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. At September 30, 2007, the carrying value of our fixed-term debt accounted for under the amortized cost method was $3.0 billion (fair value – $3.0 billion).

Hedges

Fair Value Hedges

The company 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, 2007, the company had interest rate derivatives classified as fair value hedges outstanding for up to four years relating to fixed-rate debt.

There was no ineffectiveness recognized on derivative contracts designated as fair value hedges during the three and nine month periods ended September 30, 2007.

Cash Flow Hedges

Suncor operates in a global industry where the market price of its petroleum and natural gas products is determined based on floating benchmark indices denominated in U.S. dollars. 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 during periods of debt issuance through the use of interest rate swap transactions.

At September 30, 2007, the company had hedged a portion of its forecasted Canadian and U.S. dollar denominated cash flows subject to U.S. dollar WTI commodity risk for 2007 and 2008, as well as cash flows related to natural gas production and refinery operations in 2007 and 2008.

The 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, 2007 was a gain of $2 million. During the nine month period ended September 30, 2007, the earnings impact was a loss of $4 million, net of income taxes of $2 million.

As at September 30, 2007, assets increased by $14 million and liabilities increased by $11 million as a result of recording derivative instruments at fair value in accordance with the new standards.

The fair value of hedging derivative financial instruments as recorded, is the estimated amount, based on broker quotes and/or internal valuation models, that the company would receive (pay) to terminate the contracts. Such amounts were as follows:

($ millions)	**September 30 2007**	December 31 2006
Revenue hedge swaps and collars	**—**	22
Fixed to float interest rate swaps	**6**	16
Specific cash flow hedges of individual transactions	**6**	(4)
Fair value of outstanding hedging derivative financial instruments	**12**	34

Accumulated Other Comprehensive Income (OCI)

A reconciliation of changes in accumulated OCI attributable to derivative hedging activities for the nine month period ending September 30, 2007 is as follows:

($ millions)	**2007**
OCI attributable to derivatives and hedging activities, recorded upon initial adoption on January 1, 2007, net of income taxes of $5	**8**
Current period net changes arising from cash flow hedges, net of income taxes of $5	**19**
Net unrealized hedging gains at the beginning of the period reclassified to earnings during the period, net of income taxes of $2	**(3)**
OCI attributable to derivatives and hedging activities, end of period, net of income taxes of $8	**24**

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 trading activities are accounted for using the mark-to-market method and, as such, all financial instruments are recorded at fair value at each balance sheet date. 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 trading and marketing expenses in the Consolidated Statements of Earnings. The net pretax earnings (loss) for the three and nine month periods ended September 30 were as follows:

Net Pretax Earnings (Loss)

	Third quarter		Nine months ended September 30	
($ millions)	**2007**	2006	**2007**	2006
Physical energy contracts trading activity	**5**	14	**26**	30
Financial energy contracts trading activity	**(3)**	(2)	**(7)**	(3)
General and administrative costs	**(1)**	(1)	**(2)**	(2)
Total	**1**	11	**17**	25

The fair value of unsettled (unrealized) financial energy trading assets and liabilities are as follows:

($ millions)	**September 30 2007**	December 31 2006
Energy trading assets	**2**	16
Energy trading liabilities	**13**	13
Net energy trading assets (liabilities)	**(11)**	3

Change in Fair Value of Net Assets

($ millions)	2007
Fair value of contracts outstanding at December 31, 2006	3
Fair value of contracts realized during the period	**(8)**
Fair value of contracts entered into during the period	**(7)**
Changes in values attributable to market price and other market changes	**1**
Fair value of contracts outstanding at September 30, 2007	**(11)**

The source of the valuations of the above contracts is based on actively quoted prices and/or internal model valuations.

5. FINANCING INCOME

	Third quarter		Nine months ended September 30	
($ millions)	2007	2006	2007	2006
Interest expense on debt	**51**	35	**131**	112
Capitalized interest	**(51)**	(30)	**(131)**	(94)
Net interest expense	**—**	5	**—**	18
Foreign exchange gain on long-term debt	**(126)**	—	**(233)**	(51)
Other foreign exchange loss (gain)	**26**	(5)	**48**	20
Total financing income	**(100)**	—	**(185)**	(13)

6. RECONCILIATION OF BASIC AND DILUTED EARNINGS PER COMMON SHARE

	Third quarter		Nine months ended September 30	
($ millions)	2007	2006	2007	2006
Net earnings	**677**	682	**1 869**	2 613
(millions of common shares)				
Weighted-average number of common shares	**462**	459	**461**	459
Dilutive securities:				
Options issued under stock-based compensation plans	**10**	11	**10**	11
Weighted-average number of diluted common shares	**472**	470	**471**	470
(dollars per common share)				
Basic earnings per share [(a)]	**1.47**	1.48	**4.06**	5.69
Diluted earnings per share [(b)]	**1.43**	1.45	**3.97**	5.56

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

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

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

7. STOCK-BASED COMPENSATION

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

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

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

A performance share unit is an award entitling employees to receive a payment ranging from zero to a maximum of 150% of the value of a common share contingent upon Suncor's shareholder return over a three year period relative to a peer group of companies.

(a) Stock Option Plans:

(i) SunShare 2012 Performance Stock Option Plan

On September 28, 2007, the company granted 7,696,000 options to all eligible permanent full-time and part-time employees, both executive and non-executive, under its new employee stock option incentive plan ("SunShare 2012") which was approved at the Annual and Special Meeting of shareholders on April 26, 2007. Under SunShare 2012, meeting specified performance targets may trigger the vesting of some options, such that 25% of outstanding options may vest on January 1, 2010, and the remaining 75% of outstanding options may vest on January 1, 2013. All unvested options at January 1, 2013, which have not previously expired or been cancelled, will automatically expire.

(ii) SunShare Performance Stock Option Plan

Under the SunShare long-term incentive plan, the company granted 273,000 options to new employees in the third quarter of 2007, for a total of 1,033,000 options granted in the nine months ended September 30, 2007 (634,000 options granted during the third quarter of 2006; 1,232,000 options granted in the nine months ended September 30, 2006).

On April 30, 2008, 50% of the outstanding, unvested SunShare options will vest. The remaining 50% of the outstanding, unvested SunShare options may vest on April 30, 2008 if the final predetermined performance criterion is met. If the performance criterion is not met, the unvested options that have not previously expired or been cancelled, will automatically vest on January 1, 2012. Management believes that it is highly likely the final performance criterion will be met and that all unvested SunShare options at April 30, 2008 will therefore vest. Stock-based compensation expense has been recorded to reflect this assumption.

(iii) Executive Stock Option Plan

Under this plan, the company granted 22,000 common share options in the third quarter of 2007, for a total of 479,000 options granted in the nine months ended September 30, 2007 (1,000 options granted during the third quarter of 2006; 533,000 granted in the nine months ended September 30, 2006) to non-employee directors and certain executives and other senior members of the company. The exercise price of an option is equal to the market value of the common shares at the date of the grant. Options granted have a ten-year life and vest annually over a three-year period.

(iv) Key Contributor Stock Option Plan

Under this plan, the company granted 6,000 common share options in the third quarter of 2007, for a total of 1,182,000 options granted in the nine months ended September 30, 2007 (10,000 options granted during the third quarter of 2006; 1,049,000 granted in the nine months ended September 30, 2006) to non-insider senior managers and key employees. The exercise price of an option is equal to the market value of the common shares at the date of the grant. Options granted have a ten-year life and vest annually over a three-year period.

Fair Value of Options Granted

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

	Third Quarter		Nine months ended September 30	
	2007	2006	**2007**	2006
Quarterly dividend per share	**$0.10**	$0.08	**$0.10** *	$0.08 **
Risk-free interest rate	**4.26%**	4.14%	**4.22%**	4.11%
Expected life	**7 years**	4 years	**6 years**	5 years
Expected volatility	**30%**	30%	**30%**	29%
Weighted-average fair value per option	**$30.38**	$25.40	**$29.77**	$30.16

* In 2007, quarterly dividends of $0.08 per share were paid in the first quarter and $0.10 per share were paid in the second and third quarters.

** In 2006, quarterly dividends of $0.06 per share were paid in the first quarter and $0.08 per share were paid in the second and third quarters.

Stock-based compensation expense recognized in the third quarter of 2007 related to stock options plans was $24 million (2006 – $12 million). For the nine months ended September 30, 2007 stock-based compensation expense recognized was $62 million (2006 – $31 million).

Common share options granted prior to January 1, 2003 are not recognized as compensation expense in the Consolidated Statements of Earnings. The company's reported net earnings attributable to common shareholders and earnings per share prepared in accordance with the fair value method of accounting for stock-based compensation would have been reduced for all common share options granted prior to 2003 to the pro forma amounts stated below:

($ millions, except per share amounts)	Third quarter		Nine months ended September 30	
	2007	2006	**2007**	2006
Net earnings – as reported	**677**	682	**1 869**	2 613
Less: compensation cost under the fair value method for pre-2003 options	**3**	2	**8**	7
Pro forma net earnings	**674**	680	**1 861**	2 606
Basic earnings per share				
As reported	**1.47**	1.48	**4.06**	5.69
Pro forma	**1.46**	1.48	**4.04**	5.68
Diluted earnings per share				
As reported	**1.43**	1.45	**3.97**	5.56
Pro forma	**1.43**	1.44	**3.95**	5.54

(b) Performance Share Units (PSUs)

In the third quarter of 2007 the company issued 1,000 PSUs (2006 – 3,000). For the nine months ended September 30, 2007, the company issued 415,000 PSUs (2006 – 395,000). Expense recognized in the third quarter of 2007 was $10 million (2006 – reversal of previously recognized expense of $10 million). Expense recognized for the nine months ended September 30, 2007 was $46 million (2006 – $25 million).

8. EMPLOYEE FUTURE BENEFITS LIABILITY

The company's pension plans and other post-retirement benefits programs are described in note 8 of the company's 2006 Annual Report. The following is the status of the net periodic benefit cost for the three and nine months ended September 30.

	Pension Benefits			
	Third quarter		Nine months ended September 30	
($ millions)	**2007**	2006	**2007**	2006
Current service costs	**13**	11	**39**	33
Interest costs	**12**	10	**34**	30
Expected return on plan assets	**(11)**	(8)	**(32)**	(24)
Amortization of net actuarial loss	**6**	7	**18**	21
Net periodic benefit cost	**20**	20	**59**	60

	Other Post-retirement Benefits			
	Third quarter		Nine months ended September 30	
($ millions)	**2007**	2006	**2007**	2006
Current service costs	**1**	1	**3**	4
Interest costs	**2**	2	**6**	6
Amortization of net actuarial loss	**1**	1	**2**	1
Net periodic benefit cost	**4**	4	**11**	11

9. SUPPLEMENTAL INFORMATION

	Third quarter		Nine months ended September 30	
($ millions)	**2007**	2006	**2007**	2006
Interest paid	**56**	48	**133**	123
Income taxes paid (received)	**112**	(12)	**167**	5

Revenue Hedges

Strategic Crude Oil as at September 30, 2007

	Quantity (bpd)	Average Price (US$/bbl) [a]	Revenue Hedged (Cdn$ millions) [b]	Hedge Period [c]
Costless Collars	60 000	51.64 – 93.26	284 – 513	2007
Costless Collars	10 000	59.85 – 101.06	218 – 369	2008

Natural Gas as at September 30, 2007

	Quantity (GJ/day)	Average Price (Cdn$/GJ)	Revenue Hedged (Cdn$ millions)	Hedge Period [c]
Swaps	4 000	6.11	2	2007
Costless Collars	10 000	7.00 – 7.90	2	2007 [d]
Costless Collars	5 000	7.00 – 8.05	1	2007 [d]
Costless Collars	5 000	7.25 – 8.92	1	2007 [d]

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

(b) The revenue and margin hedged is translated to Cdn$ at the September 30, 2007 exchange rate and is subject to change as the Cdn$/US$ exchange rate fluctuates during the hedge period.

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

(d) For the period October 1 to October 31, 2007, inclusive.

10. INCOME TAXES

During the second quarter of 2007 the federal government substantively enacted a 0.5% reduction to its federal corporate tax rates. Accordingly, the company recognized a reduction in future income tax expense of $67 million related to the revaluation of its opening future income tax balances.

During the second quarter of 2006 the federal government substantively enacted a 3.1% reduction to its federal corporate tax rates. Accordingly, the company recognized a reduction in future income tax expense of $292 million related to the revaluation of its opening future income tax balances.

During the second quarter of 2006 the provincial government of Alberta substantively enacted a 1.5% reduction to its provincial corporate tax rates. Accordingly, the company recognized a reduction in future income tax expense of $127 million related to the revaluation of its opening future income tax balances.

11. ROYALTY ESTIMATE MEASUREMENT UNCERTAINTY

Our current estimation of Alberta Crown royalties is based on regulations currently in effect. The findings of the Alberta Royalty review panel have not been passed into law and not factored into the information discussed below.

Alberta Crown royalties currently in effect for each Oil Sands project require payments to the Government of Alberta based on annual gross revenues less related transportation costs (R) less allowable costs (C), including the deduction of certain capital expenditures (the 25% R-C royalty), subject to a minimum payment of 1% of R.

Oil Sands royalties payable in 2007 are highly sensitive to, among other factors, changes in crude oil and natural gas pricing, foreign exchange rates and total capital and operating costs for each project. Oil Sands pretax royalty estimate was $401 million ($291 million after tax) for the first nine months of 2007 compared to $682 million ($464 million after tax) for the first nine months of 2006. We estimate 2007 annualized Crown Royalties to be approximately $600 million ($435 million after tax) based on nine months of actual results together with 2007 forward crude oil pricing of US$78.50/bbl as at September 30, 2007, current forecasts of production, capital and operating costs for the remainder of 2007, and a Canadian/US foreign exchange rate of $1.01. Accordingly, actual results will differ, and these differences may be material. The balance of the consolidated royalty expense is in respect of natural gas royalties of $89 million ($62 million after tax).

12. LONG-TERM DEBT AND CREDIT FACILITIES

During the first quarter, the company repaid maturing 6.80% $250 million Medium Term Notes using commercial paper. Also during the first quarter, the company issued 5.39% Medium Term Notes with a principal amount of $600 million under an outstanding $2 billion debt shelf prospectus. These notes bear interest, which is paid semi-annually, and mature on March 26, 2037. The net proceeds received were used to repay commercial paper.

During the second quarter, the company issued 6.50% Notes with a principal amount of US$750 million under an outstanding US$2 billion debt shelf prospectus. These notes bear interest, which is paid semi-annually, and mature on June 15, 2038. The net proceeds received were used for general corporate purposes, including repayment of short term borrowing, supporting Suncor's ongoing capital spending program and for working capital requirements.

Also during the second quarter, our $300 million bilateral credit facility was amended and extended by one year to 2008 and the credit limit was increased by $30 million to $330 million total funds available. Our $2 billion syndicated credit facility was renegotiated and extended by one year to have a five year term expiring in June 2012 and the company's commercial paper program limit was increased by $300 million from $1.2 billion to $1.5 billion. Additionally, a $15 million revolving demand credit facility was renegotiated and increased by $15 million to $30 million.

During the third quarter, the company issued an additional US$400 million principal amount of 6.50% Notes under our outstanding US$2 billion debt shelf prospectus. These notes bear interest, which is paid semi-annually, and mature on June 15, 2038. The net proceeds received were used for general corporate purposes, including repayment of short term borrowing, supporting Suncor's ongoing capital spending program and for working capital requirements.

($ millions)	**September 30 2007**	December 31 2006
Fixed-term debt, redeemable at the option of the Company		
6.50% Notes, denominated in U.S. dollars, due in 2038 (US$1150)	**1 146**	—
5.95% Notes, denominated in U.S. dollars, due in 2034 (US$500)	**498**	583
7.15% Notes, denominated in U.S. dollars, due in 2032 (US$500)	**498**	583
5.39% Series 4 Medium Term Notes, due in 2037	**600**	—
6.70% Series 2 Medium Term Notes, due in 2011	**500**	500
6.10% Medium Term Notes, due in 2007	**—**	150
6.80% Medium Term Notes, due in 2007	**—**	250
	3 242	2 066
Revolving-term debt, with interest at variable rates		
Credit facilities drawn	**225**	—
Commercial Paper	**—**	280
Total unsecured long-term debt	**3 467**	2 346
Secured long-term debt	**1**	1
Capital leases	**38**	38
Fair value of interest rate swaps on US dollar debt securities	**6**	—
Deferred financing costs	**(44)**	(22)
Total long-term debt	**3 468**	2 363

At September 30, 2007, undrawn credit facilities were approximately $1,876 million, as follows:

($ millions)	**2007**
Facility that is fully revolving for 364 days, has a term period of one year and expires in 2008	**330**
Facility that is fully revolving for a period of five years and expires in 2012	**2 000**
Facilities that can be terminated at any time at the option of the lenders	**45**
Total available credit facilities	**2 375**
Credit facilities drawn	**225**
Credit facilities supporting outstanding commercial paper	**—**
Credit facilities supporting standby letters of credit	**274**
Total undrawn credit facilities	**1 876**

Highlights

(unaudited)

	2007	2006
Cash Flow from Operations		
(dollars per common share – basic)		
For the three months ended September 30		
Cash flow from operations (1)	**2.23**	2.51
For the nine months ended September 30		
Cash flow from operations (1)	**5.86**	8.25
Ratios		
For the twelve months ended September 30		
Return on capital employed (%) (2)	**24.0**	47.2
Return on capital employed (%) (3)	**17.7**	35.0
Net debt to cash flow from operations (times) (4)	**0.8**	0.4
Interest coverage on long-term debt (times)		
Net earnings (5)	**18.0**	28.6
Cash flow from operations (6)	**22.5**	32.9
As at September 30		
Debt to debt plus shareholders' equity (%) (7)	**24.6**	19.4
Common Share Information		
As at September 30		
Share price at end of trading		
Toronto Stock Exchange – Cdn$	**94.46**	80.19
New York Stock Exchange – US$	**94.81**	72.05
Common share options outstanding (thousands)	**27 872**	19 783
For the nine months ended September 30		
Average number outstanding, weighted monthly (thousands)	**460 789**	458 859

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

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

(2) For the twelve month period ended; net earnings (2007 – $2,109 million; 2006 – $3,300 million) adjusted for after-tax financing expenses (2007 – loss of $118 million; 2006 – income of $6 million) divided by average capital employed (2007 – $8,802 million; 2006 – $6,985 million). Average capital employed is the sum of shareholders' equity and short-term debt plus long-term debt less cash and cash equivalents, at the beginning and end of the year, divided by two, less capitalized costs related to major projects in progress (as applicable). Return on capital employed (ROCE) for Suncor operating segments as presented in the Quarterly Operating Summary is calculated in a manner consistent with consolidated ROCE. For a detailed reconciliation of ROCE prepared on an annual basis, see page 58 of Suncor's 2006 Annual Report to Shareholders.

(3) If capital employed were to include capitalized costs related to major projects in progress (average capital employed including major projects in progress: 2007 – $11,885 million; 2006 – $9,429 million), the return on capital employed would be as stated on this line.

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

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

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

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

Quarterly operating summary

(unaudited)

	For the quarter ended					Nine months ended		Total year
	Sept 30 2007	Jun 30 2007	Mar 31 2007	Dec 31 2006	Sept 30 2006	**Sept 30 2007**	Sept 30 2006	Dec 31 2006
OIL SANDS								
Production (1),(a)								
Total production	**239.1**	202.3	248.2	266.4	242.8	**229.8**	258.1	260.0
Firebag	**35.8**	36.2	35.3	35.1	37.2	**35.8**	33.3	33.7
Sales (a)								
Light sweet crude oil	**99.3**	100.0	105.5	113.7	84.9	**101.6**	109.4	110.5
Diesel	**23.9**	20.3	29.5	24.0	20.7	**24.6**	29.6	28.2
Light sour crude oil	**94.1**	84.2	112.7	126.8	125.8	**96.9**	115.3	118.2
Bitumen	**6.6**	3.8	6.8	9.7	6.6	**5.7**	5.1	6.2
Total sales	**223.9**	208.3	254.5	274.2	238.0	**228.8**	259.4	263.1
Average sales price (2),(b)								
Light sweet crude oil	**81.00**	75.64	68.63	64.51	78.11	**74.87**	74.90	71.98
Other (diesel, light sour crude oil and bitumen)	**73.76**	66.74	63.62	57.91	68.60	**67.84**	68.09	65.17
Total	**76.97**	71.01	65.70	60.65	71.99	**71.02**	70.96	68.03
Total *	**76.97**	71.01	65.61	60.65	71.99	**70.99**	70.96	68.03
Cash operating costs and Total operating costs – Total operations (c)								
Cash costs	**23.00**	28.40	21.75	22.65	21.00	**24.15**	17.30	18.70
Natural gas	**2.10**	4.20	4.50	3.00	2.60	**3.55**	2.85	2.90
Imported bitumen	**—**	0.10	0.05	—	0.10	**0.05**	0.10	0.10
Cash operating costs (3)	**25.10**	32.70	26.30	25.65	23.70	**27.75**	20.25	21.70
Project start-up costs	**1.10**	1.15	0.10	0.25	0.35	**0.75**	0.45	0.40
Total cash operating costs (4)	**26.20**	33.85	26.40	25.90	24.05	**28.50**	20.70	22.10
Depreciation, depletion and amortization	**5.70**	5.85	4.45	4.25	4.30	**5.30**	4.00	4.05
Total operating costs (5)	**31.90**	39.70	30.85	30.15	28.35	**33.80**	24.70	26.15
Cash operating costs and Total operating costs – In-situ bitumen production only (c)								
Cash costs	**11.85**	10.60	11.05	8.05	5.55	**11.15**	6.60	8.95
Natural gas	**9.10**	10.60	11.05	9.90	7.60	**10.25**	7.80	8.35
Cash operating costs (6)	**20.95**	21.20	22.10	17.95	13.15	**21.40**	14.40	17.30
Firebag start-up costs	**—**	—	—	—	—	**—**	2.30	1.70
Total cash operating costs (7)	**20.95**	21.20	22.10	17.95	13.15	**21.40**	16.70	19.00
Depreciation, depletion and amortization	**6.70**	5.75	5.35	6.20	5.55	**5.95**	5.30	5.55
Total operating costs (8)	**27.65**	26.95	27.45	24.15	18.70	**27.35**	22.00	24.55
(for the period ended)								
Capital employed (i)	**6 037**	5 016	5 134	5 015	5 491			
(for the twelve months ended)								
Return on capital employed (j)	**32.8**	34.4	47.6	53.5	57.7			
Return on capital employed (j)****	**22.0**	23.6	34.7	40.1	43.6			

Quarterly operating summary (continued)

(unaudited)

	For the quarter ended					Nine months ended		Total year
	Sept 30 2007	Jun 30 2007	Mar 31 2007	Dec 31 2006	Sept 30 2006	**Sept 30 2007**	Sept 30 2006	Dec 31 2006
NATURAL GAS								
Gross production **								
Natural gas (d)	**193**	191	191	192	191	**192**	192	191
Natural gas liquids (a)	**2.4**	2.3	2.4	2.1	2.1	**2.4**	2.4	2.3
Crude oil (a)	**0.7**	0.7	0.7	0.5	0.7	**0.7**	0.8	0.7
Total gross production (e)	**35.2**	34.9	34.9	34.7	34.6	**35.0**	35.2	34.8
Total gross production (f)	**211**	209	209	208	208	**210**	211	209
Average sales price (2)								
Natural gas (g)	**5.39**	6.85	7.01	6.55	6.33	**6.41**	7.16	7.15
Natural gas (g) *	**5.14**	6.83	7.14	6.40	6.13	**6.37**	6.94	6.95
Natural gas liquids (b)	**54.81**	47.41	54.12	44.20	53.11	**52.15**	55.20	44.96
Crude oil – conventional (b)	**69.42**	63.71	65.49	51.20	84.95	**66.24**	72.79	74.83
Net wells drilled								
Conventional – Exploratory ***	**1**	3	4	4	1	**8**	7	11
– Development	**2**	1	8	6	6	**11**	12	18
	3	4	12	10	7	**19**	19	29
(for the period ended)								
Capital employed (i)	**1 090**	1 079	1 063	857	775			
(for the twelve months ended)								
Return on capital employed (j)	**(0.6)**	0.6	8.5	14.9	27.7			
REFINING AND MARKETING								
Refined product sales (h)								
Transportation fuels								
Gasoline								
Retail	**5.1**	5.2	5.4	5.5	5.3	**5.3**	5.2	5.3
Other	**12.0**	11.7	11.8	11.0	11.4	**11.9**	10.6	10.6
Distillate	**10.8**	10.5	10.3	8.8	8.5	**10.5**	8.4	8.5
Total transportation fuel sales	**27.9**	27.4	27.5	25.3	25.2	**27.7**	24.2	24.4
Petrochemicals	**0.9**	1.3	0.8	0.4	1.0	**1.0**	1.0	0.9
Asphalt	**2.1**	1.8	1.3	0.8	1.6	**1.7**	1.3	1.2
Other	**4.2**	4.1	2.0	2.6	3.6	**3.4**	3.2	3.0
Total refined product sales	**35.1**	34.6	31.6	29.1	31.4	**33.8**	29.7	29.5
Crude oil supply and refining								
Processed at refineries (h)	**25.9**	27.6	24.6	19.4	24.2	**26.1**	22.5	21.7
Utilization of refining capacity (j)	**102**	108	97	76	95	**102**	89	85
(for the period ended)								
Capital employed (i)	**2 144**	1 852	1 928	1 818	1 629			
(for the twelve months ended)								
Return on capital employed (j)	**20.0**	26.2	22.7	20.4	30.1			
Return on capital employed (j) ****	**16.9**	19.7	15.6	12.5	16.5			

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 Natural Gas 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