second quarter 2006

Report to shareholders for the period ended June 30, 2006

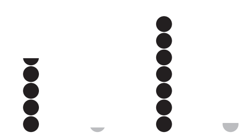
> growing strategically

Suncor Energy generates strong earnings and cash flow during second quarter

All financial figures are unaudited and in Canadian dollars unless noted otherwise. Certain prior period amounts have been restated to conform to the current year's presentation. Certain financial measures referred to in this document are not prescribed by generally accepted accounting principles (GAAP). For a description of these measures, see "Non-GAAP Financial Measures" in Suncor's 2006 second quarter management's discussion and analysis (MD&A). 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.

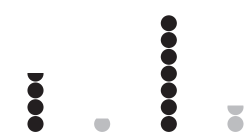
Suncor Energy Inc. recorded second quarter 2006 net earnings of $1.218 billion ($2.65 per common share), compared to $83 million ($0.18 per common share) in the second quarter of 2005. Excluding the impact of the reduction of federal and Province of Alberta income tax rates and the effects of unrealized foreign exchange gains on the company's U.S. dollar denominated long-term debt, 2006 second quarter net earnings were $755 million ($1.64 per common share), compared to $38 million ($0.08 per common share, excluding the impact of insurance proceeds) in the second quarter of 2005. Cash flow from operations was $1.320 billion in the second quarter of 2006, compared to $305 million in the second quarter of 2005.

Earnings by Quarter
($ millions)



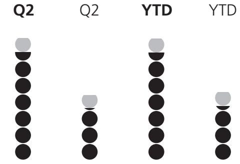
	2006 Q2	2005 Q2	**2006 YTD**	2005 YTD
	1 218	83	**1 931**	150

Cash Flow from Operations by Quarter
($ millions)



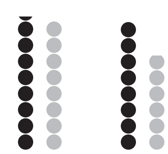
	2006 Q2	2005 Q2	**2006 YTD**	2005 YTD
	1 320	305	**2 634**	599

Production
(thousands of barrels of oil equivalent per day)



	2006 Q2	2005 Q2	**2006 YTD**	2005 YTD
Natural Gas	**35.1**	32.4	**35.5**	34.0
Oil Sands	**267.3**	128.2	**266.0**	134.1
Total	**302.4**	160.6	**301.5**	168.1

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



	2006	2005
Return on average shareholder's equity	**45.5**	17.5
Return on capital employed	**43.9**	12.9

"We will continue to focus our performance on maintaining a steady state, and operating in a reliable and safe manner." **Rick George** president and chief executive officer

The increase in net earnings was primarily due to higher oil sands production, strong commodity prices and lower income taxes due to lower federal and Alberta provincial income tax rates. Comparative production during the second quarter of 2005 was lower primarily as a result of equipment damaged by a January 2005 fire. These positive net earnings impacts were partially offset by the strengthening of the Canadian dollar and higher oil sands operating costs resulting from increased production volumes and higher royalty expenses. The same factors impacted cash flow from operations, excluding the impact of lower tax rates.

Net earnings for the first six months of 2006 were $1.931 billion ($4.21 per common share), compared to $150 million ($0.33 per common share) for the same period in 2005. Cash flow from operations for the first six months of 2006 was $2.634 billion, compared to $599 million in the first six months of 2005. Excluding the impacts of insurance proceeds, income tax revaluations and unrealized foreign exchange gains, net earnings for the first half of 2006 were $1.264 billion compared to $78 million in the same period for 2005.

Suncor's total upstream production averaged 302,400 barrels of oil equivalent (boe) per day during the second quarter of 2006, compared to 160,600 boe per day in the second quarter of 2005. Oil Sands production during the second quarter of 2006 averaged 267,300 barrels per day (bpd). This consisted of 258,800 bpd of synthetic crude oil and 8,500 bpd of bitumen, which was sold directly to the market. Production during the second quarter of 2005 averaged 128,200 bpd, including 9,600 bpd of bitumen. Natural gas production in the second quarter of 2006 was 189 million cubic feet (mmcf) per day, compared to second quarter 2005 production of 175 mmcf per day.

During the second quarter of 2006, Oil Sands cash operating costs averaged $18.30 per barrel, compared to $27.10 per barrel during the second quarter of 2005. The decrease in cash operating costs per barrel is due to operating expenses being spread over significantly more barrels of production.

In Suncor's Canadian downstream operations, higher refining margins were partially offset by reduced refinery utilization compared to the second quarter of 2005. Margins were also higher in U.S. downstream operations, while refinery utilization remained consistent compared to the second quarter of 2005.

"Steady production across all our businesses was a key contributor to solid earnings and cash flow," said Rick George, president and chief executive officer. "We will continue to focus our performance on maintaining a steady state, and operating in a reliable and safe manner."

GROWTH UPDATE

Suncor's next major growth phase targets an increase in oil sands production capacity to 350,000 bpd in 2008. The centrepiece of the expansion is the addition of a third pair of cokers to Upgrader 2. Engineering on this portion of the project is nearing completion and construction is approximately 45% complete. This project is on schedule and on budget.

Work under way also includes the expansion of Suncor's Firebag in-situ operations, with construction targeted for completion in 2007. The project, which is expected to increase the bitumen production capacity of Firebag Stages 1 and 2, also includes the addition of cogeneration facilities. This project is also on schedule and on budget, with construction approximately 15% complete for the expansion project and approximately 55% complete for the cogeneration project.

In June 2006, Suncor acquired three new oil sands permits, located approximately five kilometres southwest of the company's Fort McMurray oil sands operations. The three land permits are adjacent to mining leases previously acquired by Suncor.

In July 2006, a regulatory hearing was held on Suncor's planned third upgrader and Steepbank Mine extension. During the hearing, Suncor and various stakeholders addressed the economic benefits and social and environmental challenges related to the project. The regulator is expected to deliver its written decision before the end of the year. Pending regulatory and Board of Directors approval, Suncor plans to begin construction in 2007.

The upgrader, mine and associated facilities are central to the company's goal of increasing production to between 500,000 and 550,000 bpd in the 2010 to 2012 timeframe. Suncor has not yet announced capital cost estimates for the project as these costs, together with the final configuration of the project, are still under development. However, preliminary figures including those in Suncor's Voyageur regulatory approval application, are under upward pressure. The company expects to advance project development plans and cost estimates to a level appropriate to seek Board of Directors' approval in 2007.

In its U.S. downstream operations, Suncor successfully completed a US$445 million modification to its Commerce City refinery, allowing the facility to meet new regulations for low sulphur diesel fuel. In addition to these modifications to meet clean fuels regulations, the upgrade is also expected to improve the refinery's environmental performance, and enable Suncor to integrate a broader slate of crude oil feedstocks, including oil sands sour synthetic crude.

During the second quarter of 2006, Suncor also began commissioning a diesel desulphurization unit at its Sarnia refinery (completed in July 2006). The new desulphurization unit is the first phase of a two-part expansion and upgrade of the facility. The second phase of this $800 million project is expected to increase the refinery's capacity to process sour synthetic crude oil from Suncor's oil sands operations in Fort McMurray, Alberta. This second and final phase of the project is scheduled for completion in 2007.

"Our downstream plans are closely integrated with Suncor's oil sands strategy," said George. "Finishing the work of upgrading oil sands products in Sarnia and Denver should provide a capital cost advantage over building the facilities in Fort McMurray."

Also in Suncor's Canadian downstream operations, the company began commissioning and start-up of a new ethanol facility in late June 2006 (completed in July 2006). The facility is the largest of its kind in Canada, and is expected to produce approximately 200 million litres of ethanol annually. The ethanol produced will be used for blending in gasoline products.

As Suncor invests for future growth, prudent debt management remains a priority. With oil sands production at full capacity and higher commodity prices, net debt was reduced to $2.2 billion at the end of the second quarter, compared with $2.8 billion at the end of the first quarter, 2006.

OUTLOOK FOR 2006

Suncor's outlook provides management's targets for 2006 in certain key areas of the company's business. Outlook targets are subject to change.

	Six months ended June 30, 2006	2006 Full Year Outlook
Oil Sands		
Production (bpd) (1)	**266 000**	260 000
Diesel	**13%**	11%
Sweet	**45%**	45%
Sour	**42%**	44%
Realization on crude sales basket	**WTI @ Cushing less Cdn$5.75 per barrel**	WTI @ Cushing less Cdn$5.50 to $6.50 per barrel
Cash operating costs (2)	**$18.65 per barrel**	$18.75 to $19.50 per barrel
Natural Gas		
Natural gas production (mmcf/d)	**193**	205 to 210

(1) The 260,000 bpd target consists entirely of synthetic crude oil barrels. However, Suncor-produced bitumen may be sold directly to the market depending on certain market or operational conditions. The 266,000 bpd in the first six months of 2006 includes 4,300 bpd of bitumen sold directly to the market.

(2) Effective January 1, 2006, cash operating costs per barrel, before commissioning and start-up costs, reflect a change in accounting policy to expense overburden costs as incurred (see page 13 of Suncor's second quarter 2006 MD&A). The change in accounting policy for overburden resulted in non-cash costs being reclassified to cash costs. Therefore cash operating costs per barrel projections for 2006 have increased by $2.75 per barrel from the original outlook of $16 to $16.75 per barrel. However, total operating costs are not significantly impacted. All comparative balances have been retroactively restated for these changes in all 2006 Reports to Shareholders.

Cash operating costs are sensitive to natural gas prices. The estimate of $18.75 to $19.50 per barrel assumes a natural gas price of US$6.75 per thousand cubic feet (mcf) at Henry Hub. Cash operating costs per barrel are not prescribed by 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. Accordingly, Suncor will, as part of its management's discussion and analysis, also continue to provide separate cash operating cost calculations for Firebag in-situ operations. 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" in Suncor's 2006 second quarter MD&A.

For a discussion of risks and uncertainties that may affect our financial performance, see pages 33 to 40 in our 2005 Annual Information Form.

MANAGEMENT'S DISCUSSION AND ANALYSIS

August 1, 2006

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 June 30, 2006 unaudited interim consolidated financial statements and notes. Readers should also refer to our MD&A on pages 17 to 58 of our 2005 Annual Report and to our 2005 Annual Information Form. All financial information is reported in Canadian dollars 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 56 of our 2005 Annual Report, and page 14 of this MD&A.

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

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

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

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

Additional information about Suncor filed with Canadian securities commissions and the United States Securities and Exchange Commission (SEC), including periodic quarterly and annual reports and the Annual Information Form (AIF) filed with the SEC under cover of Form 40-F, is available on-line at www.sedar.com and www.sec.gov and our website www.suncor.com. Information contained in or otherwise accessible through our website does not form a part of this MD&A. All such references are inactive textual references only.

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 many cases, are still in the early stages of development. These costs are preliminary 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 the "Significant Capital Project Update" on page 12.

SELECTED FINANCIAL INFORMATION

Industry Indicators

($ average for the period)	3 months ended June 30 (Q2) 2006	2005	6 months ended June 30 2006	2005
West Texas Intermediate (WTI) crude oil US$/barrel at Cushing	**70.70**	53.15	**67.10**	51.50
Canadian 0.3% par crude oil Cdn$/barrel at Edmonton	**78.30**	66.45	**73.70**	64.20
Light/heavy crude oil differential US$/barrel				
WTI at Cushing less Lloyd Blend at Hardisty	**17.90**	21.30	**23.45**	20.30
Natural Gas US$/mcf at Henry Hub	**6.80**	6.80	**7.90**	6.55
Natural Gas (Alberta spot) Cdn$/mcf at AECO	**6.25**	7.35	**7.75**	7.05
New York Harbour 3-2-1 crack (1) US$/barrel	**14.65**	8.40	**10.90**	7.20
Exchange rate: Cdn$:US$	**0.90**	0.80	**0.88**	0.81

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

Outstanding Share Data (as at June 30, 2006)

Common shares	**459 195 688**
Common share options – total	**19 610 092**
Common share options – exercisable (1)	**9 255 119**

(1) Options which have vested and are available for exercise.

Summary of Quarterly Results

($ millions, except per share data)	**2006 quarter ended** **June 30**	Mar. 31	2005 quarter ended Dec. 31	Sept. 30	June 30	Mar. 31	2004 quarter ended Dec. 31	Sept. 30
Revenues	**4 070**	3 858	3 521	3 149	2 385	2 074	2 333	2 332
Net earnings	**1 218**	713	693	315	83	67	326	338
Net earnings attributable to common shareholders per share								
Basic	**2.65**	1.56	1.52	0.69	0.18	0.15	0.72	0.75
Diluted	**2.59**	1.52	1.48	0.67	0.18	0.14	0.71	0.73

ANALYSIS OF CONSOLIDATED STATEMENTS OF EARNINGS AND CASH FLOWS

Net earnings for the second quarter of 2006 were $1,218 million, compared to $83 million for the second quarter of 2005. The increase in net earnings was primarily due to:

- an increase in Oil Sands crude oil production following completion of recovery work to repair portions of the plant damaged in a January 2005 fire and the subsequent expansion of synthetic crude oil production capacity to 260,000 barrels per day (bpd) in October 2005
- an increase in the average price realization for Oil Sands crude oil to $75.34 per barrel in the second quarter of 2006 from $45.98 per barrel during the second quarter of 2005
- the substantive enactment of both federal and Alberta provincial income tax rate reductions. These reductions had the following impacts on second quarter 2006 net earnings:
  i) 3.1% reduction in the federal income tax rate resulted in a $292 million reduction in federal income taxes due to the revaluation of opening deferred income tax liabilities
  ii) 1.5% reduction in the Alberta provincial income tax rate resulted in a $127 million reduction in Alberta provincial income taxes due to the revaluation of opening deferred income tax liabilities
- higher refining margins in our Canadian and U.S. downstream operations

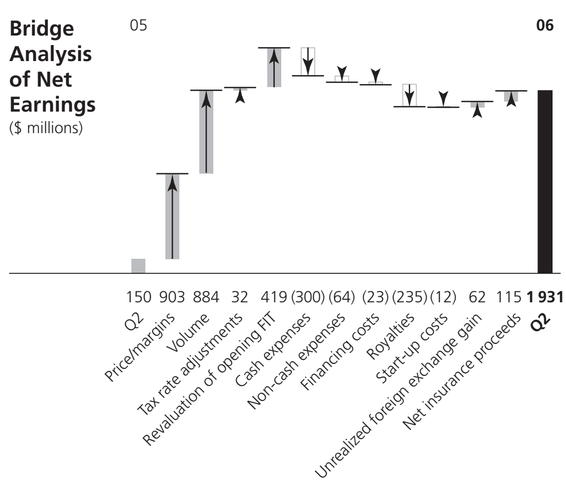
These positive net earnings impacts were partially offset by higher Oil Sands operating costs due primarily to increased production volume, higher royalty expense and higher dry hole costs in our Natural Gas business.

Cash flow from operations in the second quarter of 2006 was $1,320 million, compared to $305 million in the same period of 2005. Excluding the impact of the reduced income tax rates, the same factors impacting net earnings contributed to higher cash flow from operations.

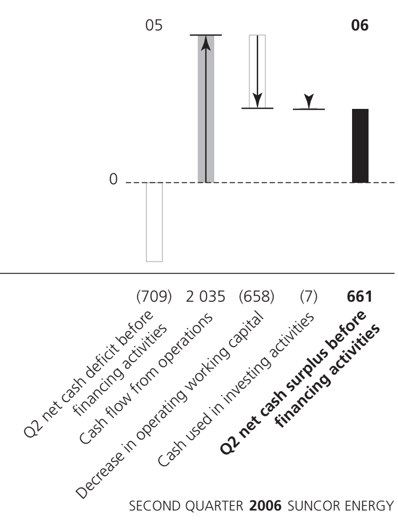
Net earnings for the first half of 2006 were $1,931 million compared to $150 million in the same period of 2005. Cash flow from operations for the first six months of 2006 was $2,634 million, compared to $599 million in the first half of 2005. The increases in both net earnings and cash flow from operations during the first half of 2006 were primarily due to the same factors listed above.

Excluding the impact of the federal and Alberta provincial income tax and large corporation tax rate reductions, our effective tax rate for the first half of 2006 was 34%, compared to 45% in the first half of 2005. This effective tax rate in the first half of 2006 is consistent with our expectations for 2006. The higher effective tax rate in the first half of 2005 was due to proportionately lower Oil Sands earnings relative to consolidated earnings. As a result, earnings subject to a higher effective tax rate (our Natural Gas business unit), and the large corporations tax (which is a capital tax insensitive to earnings), had a greater impact on the overall effective tax rate.

Bridge Analysis of Net Earnings
($ millions)



Bridge Analysis of Net Cash Flow
($ millions)



IMPACT OF TAX RATE CHANGES ON SECOND QUARTER 2006 SEGMENTED EARNINGS

A summary of the impacts on the tax rate changes on Q2 2006 earnings follows.

Tax Rate Changes ($ millions, increase (decrease) in earnings)	Oil Sands	Natural Gas	Energy Marketing & Refining – Canada	Corporate	Total
Federal	290	36	5	(39)	292
Alberta provincial	139	17	—	(29)	127
	429	53	5	(68)	419

NET EARNINGS COMPONENTS

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

	3 months ended June 30 (Q2)		6 months ended June 30	
($ millions, after tax)	**2006**	2005	**2006**	2005
Net earnings before the following items	**755**	38	**1 277**	78
Firebag Stage 2 start-up costs	**—**	—	**(13)**	—
Oil Sands fire accrued insurance proceeds (1)	**—**	58	**205**	90
Impact of income tax rate reductions on opening future income tax liabilities	**419**	—	**419**	—
Unrealized foreign exchange gain (loss) on U.S. dollar denominated long-term debt	**44**	(13)	**43**	(18)
Net earnings as reported	**1 218**	83	**1 931**	150

(1) Accrued business interruption proceeds of $385 million (US$330 million) net of income taxes and Alberta Crown royalties. For discussion see page 8.

ANALYSIS OF SEGMENTED EARNINGS AND CASH FLOW

Oil Sands

Oil Sands recorded 2006 second quarter net earnings of $1,109 million, compared with $85 million in the second quarter of 2005. Net earnings were higher primarily as a result of:

- the increase in production and sales volumes following completion of the September 2005 recovery work to repair portions of the facilities damaged in a January 2005 fire and the subsequent expansion of synthetic crude oil production capacity to 260,000 bpd in October 2005.
- an increase in the average realization of Oil Sands crude products. The price increase reflects a 33% increase in average benchmark WTI crude oil prices, the absence of crude oil hedging losses in the second quarter of 2006 (see "Derivative Financial Instruments" on page 12) and a larger portion of high value products in our 2006 sales mix, due to an unplanned hydrotreater outage that negatively impacted our sales mix in 2005.

These positive impacts were partially offset by the 13% strengthening of the Canadian dollar compared to the U.S. dollar (because crude oil is sold based on U.S. dollar benchmark prices, the stronger Canadian dollar reduces the realized value of Suncor's products).

Operating expenses before tax were $456 million in the second quarter of 2006 compared to $292 million in the second quarter of 2005. The increase in operating costs was primarily due to the following factors:

- higher total production levels
- higher contract mining costs due to the impact of the worldwide tire shortage
- increased costs at our in-situ operations primarily due to higher production volumes related to Firebag Stage 2, which began commercial operations in March 2006
- higher energy and maintenance costs due to unplanned maintenance
- a change in accounting policy for non-monetary transactions (see page 13) whereby certain natural gas costs and

offsetting revenues of $31 million were recorded in the second quarter of 2006

- higher insurance premium expense in Oil Sands. The premiums are fully offset in the corporate segment and do not impact consolidated results as they were paid to a newly formed self-insurance entity (see page 11)

Transportation and other costs were $36 million in the second quarter of 2006 compared to $21 million in the second quarter of 2005. The increase in transportation costs was due primarily to increased shipped volumes out of the Fort McMurray area.

Depreciation, depletion and amortization expense was $92 million in the second quarter of 2006 compared to $79 million during the same period in 2005. The increase was due primarily to the inclusion of newly commissioned upgrading facilities and Firebag Stage 2 operations in our depreciable cost base during the fourth quarter of 2005 and first quarter of 2006, respectively.

Alberta Crown royalty expense was $278 million in the second quarter of 2006 compared to $94 million in the second quarter of 2005. The increase was due to higher commodity prices and sales volumes, partially offset by higher operating costs and capital cost deductions. See page 8 "Oil Sands Crown Royalties and Cash Income Taxes".

Reductions in the federal and Alberta provincial income tax rates and year-to-date effective rate adjustments resulted in a combined $448 million increase in net earnings in the second quarter of 2006, reducing Oil Sands deferred tax balances.

Cash flow from operations for the second quarter of 2006 was $1,099 million, compared to $210 million in the second quarter of 2005. Excluding the impact of depreciation, depletion and amortization, and the revaluation of deferred tax balances, the increase was primarily due to the same factors that impacted net earnings.

Net earnings for the first six months of 2006 were $1,829 million, compared to $168 million in the first six months of 2005.

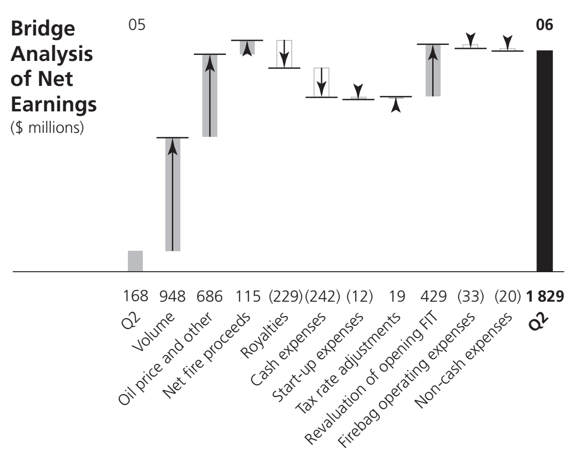
Cash flow from operations for the first six months of 2006 increased to $2,308 million from $458 million in the first six months of 2005. The year-to-date increases in net earnings and cash flow from operations were due to the same factors that impacted net earnings and cash flow from operations as outlined above.

Oil Sands production during the second quarter of 2006 averaged approximately 267,300 bpd, including 258,800 bpd of synthetic crude oil and approximately 8,500 bpd of bitumen sold directly to the market. This compared to production of approximately 128,200 bpd in the second quarter of 2005, of which 9,600 bpd of bitumen were sold directly to the market. The increase in production volumes was due to the completion in 2005 of fire damage repairs to our upgrader and subsequent commissioning of a facility that increased production capacity. During 2006, Suncor expects most of its bitumen to be upgraded into crude oil. However, under certain market or operational conditions, Suncor-produced bitumen may be sold directly to the market.

Sales during the second quarter averaged 265,300 bpd, compared with 121,100 bpd during the second quarter of 2005. The proportion of higher value diesel fuel and sweet crude products increased to 59% of total sales in the second quarter of 2006 compared to 47% in the second quarter of 2005 due to the impact of the fire and the unplanned maintenance on our hydrotreater. Sales prices averaged $75.34 per barrel during the second quarter of 2006 compared to $45.98 per barrel in the second quarter of 2005.

Effective January 1, 2006, cash operating costs per barrel, before commissioning and start-up costs, reflect a change in accounting policy to expense overburden costs as incurred (see page 13), as well as the inclusion of research and development costs. The change in accounting policy for overburden resulted in higher cash costs and lower non-cash costs. Therefore, recorded cash operating costs per barrel have increased, but total operating costs were not significantly impacted. Commencing in the first quarter of 2006, cash operating costs per barrel now reflect total Oil Sands operations including mining and in-situ production costs. In the past, operating costs per barrel for base

Bridge Analysis of Net Earnings
($ millions)



(mining and upgrading) operations and in-situ operations were disclosed separately. All comparative balances have been retroactively restated for these changes in all 2006 Reports to Shareholders.

During the second quarter, cash operating costs averaged $18.30 per barrel, compared to $27.10 per barrel during the second quarter of 2005. The decrease in cash operating costs per barrel is due to our cash operating expenses being applied to significantly more barrels of production. Refer to page 14 for further details on cash operating costs as a non-GAAP financial measure, including the calculation and reconciliation to GAAP measures.

Oil Sands Fire Insurance Update

In the second quarter of 2006 the final installment of the business interruption (BI) claim settlement from the January 2005 fire was received. The installment was accrued as net insurance proceeds in the first quarter of 2006, and did not impact second quarter net earnings.

In addition to our BI policy coverage, our primary property loss policy of US$250 million has a deductible per incident of US$10 million. During the second quarter of 2006 we received $33 million (US$30 million) in additional proceeds from the property loss policy. These proceeds had been previously accrued during 2005. There was no impact on second quarter 2006 net earnings. To date, we have received $148 million (US$125 million) in proceeds from our property loss insurers. Final settlement of the claim is anticipated in early 2007.

Oil Sands Growth Update

Suncor's next major growth phase targets an increase in oil sands production capacity to 350,000 bpd in 2008. The centrepiece of the expansion is the addition of a third pair of cokers to Upgrader 2. Engineering on this portion of the project is nearing completion and construction is approximately 45% complete. This project is on schedule and on budget.

Work under way also includes the expansion of Suncor's Firebag in-situ operations, with construction targeted for completion in 2007. The project, which is expected to increase the bitumen production capacity of Firebag Stages 1 and 2, also includes the addition of cogeneration facilities. This project is also on schedule and on budget with construction approximately 15% complete for the expansion project and approximately 55% complete for the cogeneration project.

In June 2006, Suncor acquired three new oil sands permits, located approximately five kilometres southwest of the company's Fort McMurray oil sands operations. The three land permits are adjacent to mining leases previously acquired by Suncor.

In July 2006, a regulatory hearing was held on Suncor's planned third upgrader and Steepbank Mine extension. During the hearing, Suncor and various stakeholders addressed the economic benefits and social and environmental challenges related to the project. The regulator is expected to deliver its written decision before the end of the year. Pending regulatory and Board of Directors approval, Suncor plans to begin construction in 2007.

The upgrader, mine and associated facilities are central to the company's goal of increasing production to between 500,000 and 550,000 bpd in the 2010 to 2012 timeframe. Suncor has not yet announced capital cost estimates for the project as these costs, together with the final configuration of the project, are still under development. However, preliminary figures including those in Suncor's Voyageur regulatory approval application, are under upward pressure. The company expects to advance project development plans and cost estimates to a level appropriate to seek Board of Directors' approval in 2007.

For an update on our significant growth projects currently in progress see page 12.

Oil Sands Crown Royalties and Cash Income Taxes

For a description of the Alberta Crown royalty regimes in effect for Suncor Oil Sands operations, see Note 10 to the interim financial statements or page 27 of our 2005 Annual Report.

In the second quarter of 2006 we recorded a pretax royalty estimate of $278 million ($184 million after tax) compared to $94 million ($57 million after tax) for the second quarter of 2005. We estimate 2006 annualized oil sand royalties to be approximately $1.0 billion ($675 million after tax), compared to $500 million ($305 million after tax) in 2005 based on six months of actual results including the final $385 million in business interruption insurance proceeds, basing the balance of the year estimate on 2006 forward crude oil pricing of US$75.21 as at June 30, 2006, current forecasts of production, capital and operating costs for the remainder of 2006, a Canadian/US foreign exchange rate of $0.90, and no further receipts of property loss insurance proceeds other than those recorded to date. Accordingly, actual royalties may be materially different. Royalties payable in 2006 are highly sensitive to, among other factors, changes in crude oil and natural gas pricing, timing of the receipt of property damage insurance proceeds, foreign exchange rates and total capital and operating costs for each project. The following table sets forth our estimates of royalties in the years 2006 through 2012, and certain assumptions upon which we have based our estimates.

ANTICIPATED ROYALTY BASED ON CERTAIN ASSUMPTIONS

(For the period from 2006-2012)

WTI Price/bbl (US$)	**40**	**50**	**60**
Natural gas price per mcf at Henry Hub (US$)	6.75	8.25	10.00
Light/heavy oil differential of WTI at Cushing less Maya at the U.S. Gulf Coast (US$)	9.60	12.60	15.10
Cdn$/US$ exchange rate	0.80	0.85	0.90
Crown royalty expense (based on percentage of total Oil Sands revenue) (%)			
2006-08	8-10	10-12	12-14
2009-12 (1)	5-7	6-8	6-8

(1) Assuming we exercise our option to transition our base operations in 2009 to the generic bitumen based royalty regime.

For 2007, we estimate that we will have partial cash taxes in the range of 70-100% of expected effective tax rates, based on current prices, current forecasts of production, capital and operating costs for the remainder of 2006 and 2007 and no further receipts of property loss insurance proceeds other than those recorded to date. Any cash tax in 2007 would be due in February 2008. We do not expect any significant cash tax in subsequent years until the next decade. In any particular year, our Oil Sands and NG operations may be subject to some cash income tax due to the sensitivity to crude oil and natural gas commodity price volatility and the timing of recognition of capital expenditures for income tax purposes.

As with the estimate of the 2006 Oil Sands royalties, 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 oil sands project in the case of Alberta Crown royalties). In addition, all aspects of the current Alberta oil sands royalty regime, including royalty rates and the royalty base, and income tax legislation including taxation rates, are subject to alteration by governments. Accordingly, in light of these uncertainties and the potential for unanticipated events to occur, 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. Actual differences may be material.

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

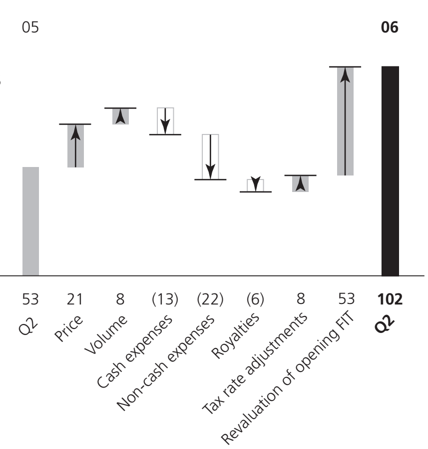
Natural Gas

Natural Gas recorded 2006 second quarter net earnings of $60 million, compared with $27 million during the second quarter of 2005. A reduction in the federal and Alberta provincial income tax rates and year-to-date effective rate adjustments resulted in a combined $61 million increase in second quarter 2006 earnings. Excluding these tax impacts, earnings in the second quarter of 2006 were lower than those in the same period in 2005 primarily as a result of an increase in dry hole costs and lower natural gas price realizations, partially offset by higher production volumes and hedging gains. Realized natural gas prices in the second quarter of 2006 were $6.38 per mcf compared to $7.29 per mcf in the second quarter of 2005, reflecting lower benchmark commodity prices.

Cash flow from operations for the second quarter of 2006 was $65 million compared with $81 million for the second quarter of 2005. Excluding the impact of lower income tax rates, the decrease was primarily due to the same factors that impacted net earnings.

For the first half of 2006, net earnings were $102 million, compared to $53 million in the first six months of 2005. This increase in earnings was due to the income tax adjustments noted above. Excluding the tax adjustments, year-to-date earnings were relatively unchanged with higher production volumes and higher price realizations being offset by higher operating costs and higher exploration expenses including dry hole costs.

Bridge Analysis of Net Earnings
($ millions)



Cash flow from operations for the first six months of 2006 was $165 million, compared to $164 million reported in the same period in 2005.

Natural gas production in the second quarter of 2006 was 189 million cubic feet (mmcf) per day, compared to 175 mmcf per day in the second quarter of 2005. Our 2006 production outlook targets an average of 205 to 210 mmcf per day for the year, exceeding Suncor's projected purchases for internal consumption.

ENERGY MARKETING & REFINING – CANADA (EM&R)

EM&R recorded 2006 second quarter net earnings of $63 million, compared to $5 million in the second quarter of 2005. The increase in net earnings was primarily due to strong refining margins and a favourable judgement of an outstanding vendor legal action in 2006. This judgement is currently under appeal. The increase in second quarter earnings was partially offset by lower retail volumes resulting from the competitive price environment in the Greater Toronto Area, and reduced refinery utilization resulting from operational issues to be addressed during the next scheduled maintenance shutdown planned for September 2006. As a result, during the second quarter of 2006, refinery utilization was 89%, compared to 100% in the second quarter of 2005. A reduction in the federal income tax rate and year-to-date effective rate adjustments resulted in a combined $10 million increase to second quarter 2006 earnings, reducing EM&R deferred and current tax balances.

Energy marketing and trading activities, including physical trading activities, resulted in net earnings of $4 million in the second quarter of 2006, compared to $3 million in the second quarter of 2005.

Cash flow from operations increased to $102 million in the second quarter of 2006 from $26 million in the second quarter of 2005. Excluding the impact of lower income tax rates, the increase was primarily due to the same factors that affected net earnings.

EM&R recorded net earnings of $81 million for the first half of 2006 compared to $2 million during the first half of 2005. This increase reflects strong refining margins in a high price environment, despite the impact of lower plant utilization resulting from operational issues in the first half of 2006.

Cash flow from operations for the first six months of 2006 was $153 million, compared to $48 million in the first six months of 2005. Excluding the impact of lower income tax rates, the increase in cash flows was primarily due to the same factors that affected net earnings.

The first phase of our diesel desulphurization and oil sands integration project began commissioning in June 2006 (completed in July 2006), in line with our revised schedule. This component of the project will enable production of Ultra Low Sulphur Diesel to comply with regulatory requirements now in effect. The full project is anticipated to be on budget.

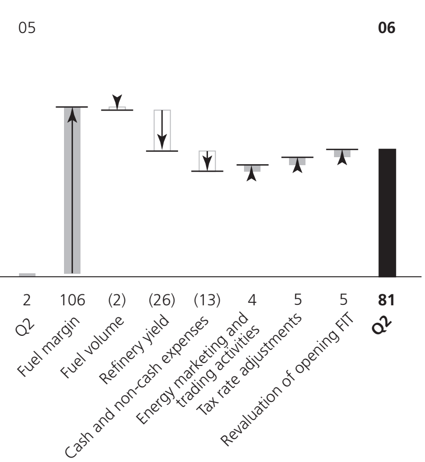
In addition, our new ethanol facility began commissioning and start-up in late June 2006 (completed in July 2006). The facility, the largest of its kind in Canada, is expected to produce approximately 200 million litres of ethanol annually. The ethanol produced will be used for blending purposes in our gasoline products. The primary feedstock for the facility is corn.

For an update on our significant growth projects currently in progress, see page 12. There is a 60 day major maintenance shutdown scheduled for the third quarter of 2006 that we expect will impact our earnings.

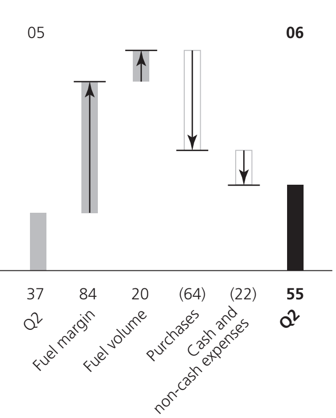
Refining & Marketing – U.S.A. (R&M)

R&M recorded net earnings of $57 million in the second quarter of 2006 compared to earnings of $31 million during the second quarter of 2005. Net earnings in 2006 were positively impacted by higher refining margins following the completion of a planned maintenance shutdown in early April 2006 and increased production volumes resulting from the acquisition of our second Commerce City refinery on May 31, 2005. The increase was partially offset by higher finished product purchases during the shutdown. During the second quarter of 2006, refinery crude utilization was 102%, unchanged from the 102% refinery crude utilization recorded in the second quarter of 2005.

Bridge Analysis of Net Earnings
($ millions)



Bridge Analysis of Net Earnings
($ millions)



Cash flow from operations for the second quarter was $96 million compared to cash flow from operations of $52 million in the second quarter of 2005. Cash flow from operations was impacted by the same factors that increased net earnings during the quarter.

R&M recorded net earnings of $55 million in the first six months of 2006, compared to net earnings of $37 million in the same period in 2005. Cash flow from operations was $96 million for the six months ended June 30, 2006, compared to $70 million during the same period in 2005. The increases in net earnings and cash flow from operations were due to the same factors that impacted net earnings and cash flow from operations in the second quarter.

Our diesel desulphurization and oil sands integration project was operational in June 2006. The new facilities allow production of Ultra Low Sulphur Diesel fuel to comply with regulatory requirements now in effect. In addition to the modifications to meet clean fuels regulations, we anticipate the upgrade will improve the refinery's environmental performance, and enables Suncor to integrate a broader slate of crude oil types, including up to 10,000 to 15,000 bpd of sour synthetic crude from the company's Canadian oil sands production. In the first quarter of 2006, the project budget was increased to a final expected cost of US$445 million from then-current estimates of US$390 million (revised from the original US$300 million). The project was completed on schedule and within the final cost estimate.

For an update on our significant growth projects currently in progress see page 12.

There are minor maintenance shutdowns scheduled for each of the two refineries in mid 2007 that we expect to impact earnings. The shutdowns are planned for approximately 12-16 days each.

Corporate

Corporate recorded net expenses in the second quarter of 2006 of $71 million, compared to net expenses of $65 million during the second quarter of 2005. After-tax unrealized foreign exchange on U.S. dollar denominated long-term debt was a $44 million gain in the second quarter of 2006 compared to a $13 million loss in the second quarter of 2005.

Net expenses were higher primarily as a result of higher depreciation, depletion and amortization expense related to the implementation of our new enterprise resource planning (ERP) system beginning January 2006, and a revaluation of federal and Alberta provincial income tax rates. Partially offsetting these factors was insurance premium revenue earned by our newly formed self-insurance company. The self-insurance premium revenue is fully offset in the Oil Sands segment, and does not impact consolidated results (see page 6).

Cash flow used in operations in the second quarter of 2006 was $42 million, compared to $64 million used in the second quarter of 2005. The decreased use of cash was primarily due to insurance related costs.

Corporate had net expenses of $136 million in the first six months of 2006, compared to $110 million in the same period of 2005. The increase in expenses, excluding unrealized foreign exchange, was primarily due to the same factors that affected net earnings in the second quarter. After-tax unrealized foreign exchange on our U.S. dollar denominated debt was a $43 million gain for the first six months of 2006, compared to an $18 million loss for the same period in 2005.

Cash flow used in operations was $88 million in the first half of 2006 compared to $141 million in the first half of 2005. The decreased use of cash was due to the same factors impacting cash flow from operations for the second quarter of 2006.

Rate reductions in the federal and Alberta provincial income tax rates and year-to-date effective rate adjustments resulted in a combined $64 million increase in net expenses, decreasing Corporate deferred and current tax asset balances.

Analysis of Financial Condition and Liquidity

Excluding cash and cash equivalents, short-term debt and future income taxes, Suncor had an operating working capital surplus of $111 million at the end of the second quarter, compared to a deficiency of $426 million at the end of the second quarter of 2005.

During the first half of 2006, net debt decreased to approximately $2.2 billion from $2.9 billion at December 31, 2005. The decrease in debt levels was primarily a result of higher cash flow from operations and foreign exchange gains on U.S. dollar denominated debt.

During the second quarter of 2006, the following changes to our available credit facilities were completed:

- a $1.5 billion credit facility agreement was renegotiated and extended by two years, to have a five-year term maturing in June 2011. In addition, the credit limit was increased by $500 million to $2 billion total funds available
- a $200 million credit facility agreement was renegotiated and the credit limit was increased by $100 million to $300 million total funds available
- a $600 million credit facility agreement matured and was not renewed

At June 30, 2006 our undrawn lines of credit were approximately $1.8 billion. We believe we have the capital resources from our undrawn lines of credit, cash flow from operations and, if necessary, additional sources of financing to fund our 2006 capital spending program and to meet our current working capital requirements. If additional capital is required, we believe adequate additional financing is available at market terms and rates. As reported in our 2005 Annual Report, we anticipate capital spending of approximately $3.5 billion for 2006.

Effective May 15, 2006 one of our business interruption insurance providers discontinued operations. We continue to evaluate options to replace this coverage and anticipate having resolution by early 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.

(all amounts in $ millions)	Cost estimate (1)	Spent YTD in 2006	Total spent to date	Status (1)
Oil Sands				
Coker unit (2)	$2 100	$315	$1 245	Project is on schedule and on budget.
Firebag cogeneration and expansion	$400	$85	$205	Project is on schedule and on budget.
EM&R				
Diesel desulphurization and oil sands integration	$800	$175	$650	Diesel desulphurization component commissioning underway (completed in July 2006). Oil sands integration component on schedule. Project is on budget. (3)
R&M				
Diesel desulphurization and oil sands integration	$540 (US$445)	$115 (US$95)	$530 (US$435)	Project commissioning underway (completed in July 2006). In line with revised cost estimate. (4)

(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. The projects noted in the above table have cost estimates within this range of uncertainty. 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.

(2) Excludes costs associated with bitumen feed.

(3) See page 10 for discussion.

(4) See page 11 for discussion.

Suncor's Voyageur project has not yet been approved by regulators nor by Suncor's Board of Directors. Suncor has not yet announced capital cost estimates for its Voyageur project as the project cost estimates, together with the final configuration of the project, are still under development. However, preliminary figures including those in Suncor's Voyageur regulatory approval application, are under upward pressure. Detailed engineering is not expected until 2007, at which time final approval to proceed with the project will be considered by Suncor's board of directors. Subject to board and regulatory approval, the Voyageur project will be included in the above table at that time.

Derivative Financial Instruments

As at June 30, 2006, crude oil hedges totaling 50,000 bpd of production were outstanding for the remainder of 2006 and 2007. These costless collar hedges have a floor of US$50/bbl and an average ceiling of approximately US$92/bbl.

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

We had no crude oil hedging losses in the second quarter of 2006 compared to an after-tax loss of $84 million in the second quarter of 2005. This was primarily as a result of crude oil swaps in place in prior years, which expired at December 31, 2005.

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 June 30:

($ millions)	2006	2005
Revenue hedge swaps and collars	**(48)**	(292)
Margin hedge swaps	**—**	(12)
Interest rate and cross-currency interest rate swaps	**9**	40
Specific cash flow hedges of individual transactions	**8**	11
	(31)	(253)

Energy Marketing and Trading Activities

For the second quarter ended June 30, 2006, we recorded net pretax earnings of $nil compared to the $1 million loss recorded during the second quarter of 2005 related to the settlement and revaluation of financial energy trading contracts. In the second quarter, the settlement of physical trading activities resulted in net pretax earnings of $6 million compared to $7 million pretax earnings in the second quarter of 2005. These balances were included as energy marketing and trading activities in the Consolidated Statement of Earnings. The above amounts do not include the impact of related general and administrative costs. Total after-tax energy marketing and trading activities resulted in earnings of $4 million for the quarter ended June 30, 2006 compared to earnings of $3 million in the second quarter of 2005. The fair value of unsettled financial energy trading assets and liabilities at June 30, 2006 and December 31, 2005 were as follows:

($ millions)	2006	2005
Energy trading assets	**21**	82
Energy trading liabilities	**13**	70
Net energy trading assets	**8**	12

Control Environment

Based on their evaluation as of June 30, 2006, our chief executive officer and chief financial officer concluded that our disclosure controls and procedures (as defined in Rules 13(a) – 15(e) and 15(d) – 15(e) under the United States Securities Exchange Act of 1934 (the Exchange Act)) are effective to ensure that information required to be disclosed in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms. In addition, other than as described below, as of June 30, 2006, there were no changes in our internal controls over financial reporting that occurred during the six month period ended June 30, 2006 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 control and procedures and internal control over financial reporting and will make any modifications from time to time as deemed necessary.

Since the beginning of the 2006 fiscal year, our internal control over financial reporting has undergone significant changes and redesign as several business units have implemented our new ERP system, designed to support our growth plan. The business units affected by this implementation were Oil Sands, Natural Gas, EM&R – Canada, Corporate and our Major Projects group. Implementing an ERP system on a widespread basis involves major changes in business processes and extensive organizational training. We believe our phased-in approach reduces the risks associated with making these changes. In addition, we are taking the steps we believe are necessary to monitor and maintain appropriate internal controls during this transition period. These steps include deploying resources to mitigate internal control risks and performing additional verifications and testing to ensure data integrity.

The phased implementation of our ERP system is currently planned to be largely completed during the balance of 2006.

Change in Accounting Policies

(a) Overburden Removal Costs

On January 1, 2006, the company retroactively adopted EIC 160 "Stripping Costs Incurred in the Production Phase of a Mining Operation". Under the new standard, overburden removal costs should be deferred and amortized only in instances where the activity benefits future periods, otherwise the costs should be charged to earnings in the period incurred. At Suncor, overburden removal precedes mining of the oil sands deposit within the normal operating cycle, and is related to current production. In accordance with the new standard, overburden removal costs are treated as variable production costs and expensed as incurred. Previously overburden removal was deferred and amortized on a life of mine approach.

(b) Non-monetary Transactions

On January 1, 2006, the company prospectively adopted CICA Handbook section 3831 "Non-monetary Transactions". The standard requires all non-monetary transactions to be measured at fair value (if determinable) unless future cash flows are not expected to change significantly as a result of a transaction or the transaction is an exchange of a product held for sale in the ordinary course of business. The company was required to record the effects of an existing contract at Oil Sands that exchanges off-gas produced as a by-product of the upgrading operations for natural gas. An equal amount of revenues for the sale of the off-gas, and purchases of crude oil and products for the purchase of the natural gas was recorded. The amount of the gross-up of revenues and purchases of crude oil and products in the second quarter of 2006 was $31 million. For the six months ended June 30, 2006 the amount of total gross-up of revenues and purchases of crude oil and products was $79 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 June 30, 2006 interim basis, please refer to page 30 of the second quarter 2006 Report to Shareholders.

Cash flow from operations is expressed before changes in non-cash working capital. A reconciliation of net earnings to cash flow from operations is provided in the Schedules of Segmented Data, which are an integral part of Suncor's June 30, 2006 unaudited interim consolidated financial statements.

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

		3 months ended June 30 (Q2)		6 months ended June 30	
		2006	2005	**2006**	2005
Cash flow from operations ($ millions)	A	**1 320**	305	**2 634**	599
Weighted number of shares outstanding (millions of shares)	B	**459.0**	456.1	**458.6**	455.5
Cash flow from operations (per share)	(A / B)	**2.88**	0.67	**5.74**	1.32

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. Amounts included in the tables below for base operations and Firebag in-situ reconcile to the schedules of segmented data when combined.

OIL SANDS OPERATING COSTS – TOTAL OPERATIONS

		Quarter ended June 30				Six months ended June 30			
		2006		2005		**2006**		2005	
		$ millions	$/barrel	$ millions	$/barrel	$ millions	$/barrel	$ millions	$/barrel
Operating, selling and general expenses		**456**		292		**964**		613	
Less: natural gas costs and inventory changes		**(60)**		(30)		**(167)**		(105)	
Less: non-monetary transactions		**(31)**		—		**(79)**		—	
Accretion of asset retirement obligations		**7**		5		**14**		11	
Taxes other than income taxes		**9**		7		**19**		14	
Cash costs		**381**	**15.65**	274	23.50	**751**	**15.60**	533	21.95
Natural gas		**62**	**2.55**	42	3.60	**144**	**3.00**	110	4.55
Imported bitumen (net of other reported product purchases)		**2**	**0.10**	—	—	**3**	**0.05**	1	0.05
Total cash operating costs	A	**445**	**18.30**	316	27.10	**898**	**18.65**	644	26.55
In-situ (Firebag) start-up costs	B	**—**	**—**	—	—	**21**	**0.45**	—	—
Total cash operating costs after start-up costs	A+B	**445**	**18.30**	316	27.10	**919**	**19.10**	644	26.55
Depreciation, depletion and amortization		**92**	**3.80**	79	6.75	**185**	**3.85**	158	6.50
Total operating costs		**537**	**22.10**	395	33.85	**1 104**	**22.95**	802	33.05
Production (thousands of barrels per day)		**267.3**		128.2		**266.0**		134.1	

OIL SANDS OPERATING COSTS – IN-SITU BITUMEN PRODUCTION

	Quarter ended June 30				Six months ended June 30			
	2006		2005		**2006**		2005	
	$ millions	$/barrel	$ millions	$/barrel	$ millions	$/barrel	$ millions	$/barrel
Operating, selling and general expenses	**52**		30		**105**		62	
Less: natural gas costs and inventory changes	**(26)**		(13)		**(45)**		(30)	
Taxes other than income taxes	**1**		—		**2**		—	
Cash costs	**27**	**8.50**	17	21.50	**62**	**10.95**	32	12.90
Natural gas	**26**	**8.15**	13	16.40	**45**	**7.95**	30	12.10
Cash operating costs	**53**	**16.65**	30	37.90	**107**	**18.90**	62	25.00
Depreciation, depletion and amortization	**12**	**3.75**	6	7.60	**29**	**5.10**	14	5.65
Total operating costs	**65**	**20.40**	36	45.50	**136**	**24.00**	76	30.65
Production (thousands of barrels per day)	**35.0**		8.7		**31.3**		13.7	

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

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 (for example, the clean fuels refinery modifications projects in Suncor's downstream businesses); 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; the uncertainties resulting from the January 2005 fire at the Oil Sands facility and other 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; the ability and willingness of parties with whom Suncor has material relationships to perform their obligations to Suncor; and the occurrence of unexpected events such as the January 2005 fire, 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

(unaudited)

($ millions)	Second quarter 2006	Second quarter 2005 (restated) (note 2)	Six months ended June 30 2006	Six months ended June 30 2005 (restated) (note 2)
Revenues	**4 070**	2 385	**7 928**	4 459
Expenses				
Purchases of crude oil and products	**1 233**	1 039	**2 184**	1 855
Operating, selling and general (notes 2 and 6)	**654**	537	**1 426**	1 080
Energy marketing and trading activities (note 3)	**354**	214	**616**	361
Transportation and other costs	**47**	33	**98**	67
Depreciation, depletion and amortization (note 2)	**166**	137	**324**	274
Accretion of asset retirement obligations	**9**	7	**17**	15
Exploration	**31**	2	**62**	19
Royalties (note 10)	**299**	123	**628**	238
Taxes other than income taxes	**142**	126	**282**	246
Loss (gain) on disposal of assets	**1**	(1)	**(3)**	(1)
Project start-up costs	**5**	3	**26**	6
Financing expenses (income) (note 4)	**(20)**	21	**(13)**	28
	2 921	2 241	**5 647**	4 188
Earnings Before Income Taxes	**1 149**	144	**2 281**	271
Provision for (Recovery of) Income Taxes (notes 2 and 9)				
Current	**(8)**	24	**(9)**	53
Future	**(61)**	37	**359**	68
	(69)	61	**350**	121
Net Earnings	**1 218**	83	**1 931**	150
Per Common Share (dollars), (note 5)				
Basic	**2.65**	0.18	**4.21**	0.33
Diluted	**2.59**	0.18	**4.10**	0.32
Cash dividends	**0.08**	0.06	**0.14**	0.12

See accompanying notes.

CONSOLIDATED BALANCE SHEETS

(unaudited)

($ millions)	June 30 2006	December 31 2005 (restated) (note 2)
Assets		
Current assets		
Cash and cash equivalents	**158**	165
Accounts receivable	**1 260**	1 139
Inventories	**550**	523
Income taxes receivable	**32**	6
Future income taxes	**66**	83
Total current assets	**2 066**	1 916
Property, plant and equipment, net	**14 214**	12 966
Deferred charges and other (note 2)	**278**	267
Total assets	**16 558**	15 149
Liabilities and Shareholders' Equity		
Current liabilities		
Short-term debt	**8**	49
Accounts payable and accrued liabilities (note 10)	**1 626**	1 830
Taxes other than income taxes	**105**	56
Total current liabilities	**1 739**	1 935
Long-term debt	**2 340**	3 007
Accrued liabilities and other	**1 049**	1 005
Future income taxes (notes 2 and 9)	**3 545**	3 206
Shareholders' equity (see below)	**7 885**	5 996
Total liabilities and shareholders' equity	**16 558**	15 149

Shareholders' Equity

	Number (thousands)		Number (thousands)	
Share capital	**459 196**	**774**	457 665	732
Contributed surplus		**65**		50
Cumulative foreign currency translation		**(117)**		(81)
Retained earnings (note 2)		**7 163**		5 295
		7 885		5 996

See accompanying notes.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited)

($ millions)	Second quarter 2006	Second quarter 2005 (restated) (note 2)	Six months ended June 30 2006	Six months ended June 30 2005 (restated) (note 2)
Operating Activities				
Cash flow from operations	**1 320**	305	**2 634**	599
Decrease (increase) in operating working capital				
Accounts receivable	**268**	51	**(149)**	(175)
Inventories	**(103)**	(36)	**(27)**	(40)
Accounts payable and accrued liabilities	**(125)**	207	**(366)**	382
Taxes payable	**39**	(5)	**23**	(28)
Cash flow from operating activities	**1 399**	522	**2 115**	738
Cash Used in Investing Activities	**(797)**	(871)	**(1 454)**	(1 447)
Net Cash Surplus (Deficiency) Before Financing Activities	**602**	(349)	**661**	(709)
Financing Activities				
Increase (decrease) in short-term debt	**(21)**	2	**(41)**	(20)
Net increase (decrease) in other long-term debt	**(522)**	347	**(616)**	658
Issuance of common shares under stock option plan	**11**	21	**33**	52
Dividends paid on common shares	**(33)**	(26)	**(58)**	(51)
Deferred revenue	**6**	14	**16**	30
Cash provided by (used in) financing activities	**(559)**	358	**(666)**	669
Increase (Decrease) in Cash and Cash Equivalents	**43**	9	**(5)**	(40)
Effect of Foreign Exchange on Cash and Cash Equivalents	**(2)**	—	**(2)**	—
Cash and Cash Equivalents at Beginning of Period	**117**	39	**165**	88
Cash and Cash Equivalents at End of Period	**158**	48	**158**	48

See accompanying notes.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(unaudited)

($ millions)	Share Capital	Contributed Surplus	Cumulative Foreign Currency Translation	Retained Earnings
At December 31, 2004, as previously reported	651	32	(55)	4 293
Retroactive adjustment for change in accounting policy, net of tax (note 2)	—	—	—	(47)
At December 31, 2004, as restated	651	32	(55)	4 246
Net earnings	—	—	—	150
Dividends paid on common shares	—	—	—	(51)
Issued for cash under stock option plan	52	—	—	—
Issued under dividend reinvestment plan	4	—	—	(4)
Stock-based compensation expense	—	10	—	—
Foreign currency translation adjustment	—	—	3	—
At June 30, 2005	707	42	(52)	4 341
At December 31, 2005, as previously reported	732	50	(81)	5 429
Retroactive adjustment for change in accounting policy, net of tax (note 2)	—	—	—	(134)
At December 31, 2005, as restated	732	50	(81)	5 295
Net earnings	**—**	**—**	**—**	**1 931**
Dividends paid on common shares	**—**	**—**	**—**	**(58)**
Issued for cash under stock option plan	**37**	**(4)**	**—**	**—**
Issued under dividend reinvestment plan	**5**	**—**	**—**	**(5)**
Stock-based compensation expense	**—**	**19**	**—**	**—**
Foreign currency translation adjustment	**—**	**—**	**(36)**	**—**
At June 30, 2006	**774**	**65**	**(117)**	**7 163**

See accompanying notes.

SCHEDULES OF SEGMENTED DATA

(unaudited)

Second quarter

($ millions)	Oil Sands 2006	Oil Sands 2005	Natural Gas 2006	Natural Gas 2005	Energy Marketing and Refining – Canada 2006	Energy Marketing and Refining – Canada 2005	Refining and Marketing – U.S.A. 2006	Refining and Marketing – U.S.A. 2005	Corporate and Eliminations 2006	Corporate and Eliminations 2005	Total 2006	Total 2005
EARNINGS												
Revenues												
Operating revenues	**1 642**	460	**120**	117	**1 048**	887	**890**	575	**1**	—	**3 701**	2 039
Energy marketing and trading activities	**—**	—	**—**	—	**383**	232	**—**	—	**(18)**	—	**365**	232
Net insurance proceeds	**—**	113	**—**	—	**—**	—	**—**	—	**—**	—	**—**	113
Intersegment revenues	**261**	76	**11**	20	**—**	—	**—**	—	**(272)**	(96)	**—**	—
Interest	**—**	—	**—**	—	**—**	—	**1**	1	**3**	—	**4**	1
	1 903	649	**131**	137	**1 431**	1 119	**891**	576	**(286)**	(96)	**4 070**	2 385
Expenses												
Purchases of crude oil and products	**14**	12	**—**	—	**768**	658	**713**	453	**(262)**	(84)	**1 233**	1 039
Operating, selling and general	**456**	292	**27**	23	**97**	117	**41**	39	**33**	66	**654**	537
Energy marketing and trading activities	**—**	—	**—**	—	**377**	227	**—**	—	**(23)**	(13)	**354**	214
Transportation and other costs	**36**	21	**5**	6	**3**	2	**3**	4	**—**	—	**47**	33
Depreciation, depletion and amortization	**92**	79	**38**	30	**22**	18	**8**	6	**6**	4	**166**	137
Accretion of asset retirement obligations	**7**	5	**2**	1	**—**	1	**—**	—	**—**	—	**9**	7
Exploration	**—**	—	**31**	2	**—**	—	**—**	—	**—**	—	**31**	2
Royalties (note 10)	**278**	94	**21**	29	**—**	—	**—**	—	**—**	—	**299**	123
Taxes other than income taxes	**20**	7	**2**	1	**84**	89	**36**	29	**—**	—	**142**	126
Loss (gain) on disposal of assets	**—**	—	**—**	—	**—**	(1)	**1**	—	**—**	—	**1**	(1)
Project start-up costs	**3**	3	**—**	—	**2**	—	**—**	—	**—**	—	**5**	3
Financing expenses (income)	**—**	—	**—**	—	**—**	—	**—**	—	**(20)**	21	**(20)**	21
	906	513	**126**	92	**1 353**	1 111	**802**	531	**(266)**	(6)	**2 921**	2 241
Earnings (loss) before income taxes	**997**	136	**5**	45	**78**	8	**89**	45	**(20)**	(90)	**1 149**	144
Income taxes	**112**	(51)	**55**	(18)	**(15)**	(3)	**(32)**	(14)	**(51)**	25	**69**	(61)
Net earnings (loss)	**1 109**	85	**60**	27	**63**	5	**57**	31	**(71)**	(65)	**1 218**	83

SCHEDULES OF SEGMENTED DATA (continued)

(unaudited)

Second quarter

($ millions)	Oil Sands 2006	Oil Sands 2005	Natural Gas 2006	Natural Gas 2005	Energy Marketing and Refining – Canada 2006	Energy Marketing and Refining – Canada 2005	Refining and Marketing – U.S.A. 2006	Refining and Marketing – U.S.A. 2005	Corporate and Eliminations 2006	Corporate and Eliminations 2005	Total 2006	Total 2005
CASH FLOW BEFORE FINANCING ACTIVITIES												
Cash flow from (used in) operating activities:												
Cash flow from (used in) operations												
Net earnings (loss)	**1 109**	85	**60**	27	**63**	5	**57**	31	**(71)**	(65)	**1 218**	83
Exploration expenses	**—**	—	**20**	2	**—**	—	**—**	—	**—**	—	**20**	2
Non-cash items included in earnings												
Depreciation, depletion and amortization	**92**	79	**38**	30	**22**	18	**8**	6	**6**	4	**166**	137
Income taxes	**(112)**	51	**(55)**	18	**15**	3	**32**	14	**59**	(49)	**(61)**	37
Loss (gain) on disposal of assets	**—**	—	**—**	—	**—**	(1)	**1**	—	**—**	—	**1**	(1)
Stock-based compensation expense	**—**	—	**—**	—	**—**	—	**—**	—	**10**	6	**10**	6
Other	**16**	(2)	**2**	4	**2**	1	**(2)**	1	**(47)**	19	**(29)**	23
Increase (decrease) in deferred credits and other	**(6)**	(3)	**—**	—	**—**	—	**—**	—	**1**	21	**(5)**	18
Total cash flow from (used in) operations	**1 099**	210	**65**	81	**102**	26	**96**	52	**(42)**	(64)	**1 320**	305
Decrease (increase) in operating working capital	**(22)**	108	**(59)**	(11)	**7**	19	**12**	15	**141**	86	**79**	217
Total cash flow from (used in) operating activities	**1 077**	318	**6**	70	**109**	45	**108**	67	**99**	22	**1 399**	522
Cash from (used in) investing activities:												
Capital and exploration expenditures	**(555)**	(510)	**(127)**	(72)	**(117)**	(114)	**(56)**	(96)	**(10)**	(12)	**(865)**	(804)
Acquisition of Denver refinery and related assets	**—**	—	**—**	—	**—**	—	**—**	(62)	**—**	—	**—**	(62)
Deferred maintenance shutdown expenditures	**—**	(35)	**—**	—	**(1)**	—	**(9)**	(1)	**—**	—	**(10)**	(36)
Deferred outlays and other investments	**(2)**	—	**—**	—	**—**	(1)	**5**	—	**9**	(1)	**12**	(2)
Proceeds from disposals	**—**	—	**1**	—	**3**	1	**—**	—	**—**	—	**4**	1
Proceeds from property loss	**29**	—	**—**	—	**—**	—	**—**	—	**—**	—	**29**	—
Decrease (increase) in investing working capital	**66**	17	**—**	—	**7**	1	**(40)**	14	**—**	—	**33**	32
Total cash (used in) investing activities	**(462)**	(528)	**(126)**	(72)	**(108)**	(113)	**(100)**	(145)	**(1)**	(13)	**(797)**	(871)
Net cash surplus (deficiency) before financing activities	**615**	(210)	**(120)**	(2)	**1**	(68)	**8**	(78)	**98**	9	**602**	(349)

SCHEDULES OF SEGMENTED DATA (continued)

(unaudited)

Six months ended June 30

($ millions)	Oil Sands 2006	Oil Sands 2005	Natural Gas 2006	Natural Gas 2005	Energy Marketing and Refining – Canada 2006	Energy Marketing and Refining – Canada 2005	Refining and Marketing – U.S.A. 2006	Refining and Marketing – U.S.A. 2005	Corporate and Eliminations 2006	Corporate and Eliminations 2005	Total 2006	Total 2005
EARNINGS												
Revenues												
Operating revenues	**3 192**	1 013	**294**	248	**1 940**	1 652	**1 476**	986	**2**	1	**6 904**	3 900
Energy marketing and trading activities	**—**	—	**—**	—	**657**	382	**—**	—	**(23)**	—	**634**	382
Net insurance proceeds	**385**	176	**—**	—	**—**	—	**—**	—	**—**	—	**385**	176
Intersegment revenues	**446**	153	**17**	26	**—**	—	**—**	—	**(463)**	(179)	**—**	—
Interest	**—**	—	**—**	—	**—**	—	**1**	1	**4**	—	**5**	1
	4 023	1 342	**311**	274	**2 597**	2 034	**1 477**	987	**(480)**	(178)	**7 928**	4 459
Expenses												
Purchases of crude oil and products	**17**	21	**—**	—	**1 414**	1 219	**1 208**	782	**(455)**	(167)	**2 184**	1 855
Operating, selling and general	**964**	613	**51**	44	**221**	225	**84**	71	**106**	127	**1 426**	1 080
Energy marketing and trading activities	**—**	—	**—**	—	**643**	374	**—**	—	**(27)**	(13)	**616**	361
Transportation and other costs	**73**	45	**11**	11	**4**	3	**10**	8	**—**	—	**98**	67
Depreciation, depletion and amortization	**185**	158	**72**	61	**42**	36	**12**	12	**13**	7	**324**	274
Accretion of asset retirement obligations	**14**	11	**3**	3	**—**	1	**—**	—	**—**	—	**17**	15
Exploration	**22**	10	**40**	9	**—**	—	**—**	—	**—**	—	**62**	19
Royalties (note 10)	**563**	181	**65**	57	**—**	—	**—**	—	**—**	—	**628**	238
Taxes other than income taxes	**41**	14	**2**	1	**163**	172	**76**	59	**—**	—	**282**	246
Loss (gain) on disposal of assets	**—**	—	**(4)**	—	**—**	(1)	**1**	—	**—**	—	**(3)**	(1)
Project start-up costs	**24**	6	**—**	—	**2**	—	**—**	—	**—**	—	**26**	6
Financing expenses (income)	**—**	—	**—**	—	**—**	—	**—**	—	**(13)**	28	**(13)**	28
	1 903	1 059	**240**	186	**2 489**	2 029	**1 391**	932	**(376)**	(18)	**5 647**	4 188
Earnings (loss) before income taxes	**2 120**	283	**71**	88	**108**	5	**86**	55	**(104)**	(160)	**2 281**	271
Income taxes	**(291)**	(115)	**31**	(35)	**(27)**	(3)	**(31)**	(18)	**(32)**	50	**(350)**	(121)
Net earnings (loss)	**1 829**	168	**102**	53	**81**	2	**55**	37	**(136)**	(110)	**1 931**	150
As at June 30												
TOTAL ASSETS	**12 649**	10 005	**1 390**	1 089	**2 850**	1 574	**1 257**	1 092	**(1 588)**	(479)	**16 558**	13 281

SCHEDULES OF SEGMENTED DATA (continued)

(unaudited)

Six months ended June 30

($ millions)	Oil Sands 2006	Oil Sands 2005	Natural Gas 2006	Natural Gas 2005	Energy Marketing and Refining – Canada 2006	Energy Marketing and Refining – Canada 2005	Refining and Marketing – U.S.A. 2006	Refining and Marketing – U.S.A. 2005	Corporate and Eliminations 2006	Corporate and Eliminations 2005	Total 2006	Total 2005
CASH FLOW BEFORE FINANCING ACTIVITIES												
Cash flow from (used in) operating activities:												
Cash flow from (used in) operations												
Net earnings (loss)	**1 829**	168	**102**	53	**81**	2	**55**	37	**(136)**	(110)	**1 931**	150
Exploration expenses	**—**	—	**25**	9	**—**	—	**—**	—	**—**	—	**25**	9
Non-cash items included in earnings												
Depreciation, depletion and amortization	**185**	158	**72**	61	**42**	36	**12**	12	**13**	7	**324**	274
Income taxes	**291**	115	**(31)**	35	**27**	3	**31**	18	**41**	(103)	**359**	68
Loss (gain) on disposal of assets	**—**	—	**(4)**	—	**—**	(1)	**1**	—	**—**	—	**(3)**	(1)
Stock-based compensation expense	**—**	—	**—**	—	**—**	—	**—**	—	**19**	10	**19**	10
Other	**14**	23	**1**	6	**3**	8	**—**	3	**(26)**	7	**(8)**	47
Increase (decrease) in deferred credits and other	**(11)**	(6)	**—**	—	**—**	—	**(3)**	—	**1**	48	**(13)**	42
Total cash flow from (used in) operations	**2 308**	458	**165**	164	**153**	48	**96**	70	**(88)**	(141)	**2 634**	599
Decrease (increase) in operating working capital	**(222)**	72	**(41)**	(27)	**(76)**	(42)	**32**	(58)	**(212)**	194	**(519)**	139
Total cash flow from (used in) operating activities	**2 086**	530	**124**	137	**77**	6	**128**	12	**(300)**	53	**2 115**	738
Cash from (used in) investing activities:												
Capital and exploration expenditures	**(962)**	(880)	**(242)**	(154)	**(235)**	(192)	**(164)**	(163)	**(14)**	(24)	**(1 617)**	(1 413)
Acquisition of Denver refinery and related assets	**—**	—	**—**	—	**—**	—	**—**	(62)	**—**	—	**—**	(62)
Deferred maintenance shutdown expenditures	**—**	(60)	**—**	—	**(1)**	—	**(51)**	(1)	**—**	—	**(52)**	(61)
Deferred outlays and other investments	**(2)**	(1)	**—**	—	**—**	(2)	**5**	—	**7**	(1)	**10**	(4)
Proceeds from disposals	**—**	21	**14**	—	**3**	1	**—**	—	**—**	—	**17**	22
Proceeds from property loss	**29**	—	**—**	—	**—**	—	**—**	—	**—**	—	**29**	—
Decrease (increase) in investing working capital	**183**	48	**—**	—	**14**	9	**(38)**	14	**—**	—	**159**	71
Total cash (used in) investing activities	**(752)**	(872)	**(228)**	(154)	**(219)**	(184)	**(248)**	(212)	**(7)**	(25)	**(1 454)**	(1 447)
Net cash surplus (deficiency) before financing activities	**1 334**	(342)	**(104)**	(17)	**(142)**	(178)	**(120)**	(200)	**(307)**	28	**661**	(709)

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.

In the opinion of management, these interim consolidated financial statements contain all adjustments of a normal and recurring nature necessary to present fairly Suncor Energy Inc.'s (Suncor) financial position at June 30, 2006 and the results of its operations and cash flows for the three and six month periods ended June 30, 2006 and 2005.

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

2. CHANGES IN ACCOUNTING POLICIES

(a) Overburden Removal Costs

On January 1, 2006, the company retroactively adopted EIC 160 "Stripping Costs Incurred in the Production Phase of a Mining Operation". Under the new standard, overburden removal costs should be deferred and amortized only in instances where the activity benefits future periods, otherwise the costs should be charged to earnings in the period incurred. At Suncor, overburden removal precedes mining of the oil sands deposit within the normal operating cycle, and is related to current production. In accordance with the new standard, overburden removal costs are treated as variable production costs and expensed as incurred. Previously overburden removal was deferred and amortized on a life-of-mine approach. The impact of adopting this accounting standard is as follows:

Change in Consolidated Balance Sheets

	As at June 30	
($ millions, (decrease))	**2006**	2005
Deferred charges and other	**(244)**	(160)
Total assets	**(244)**	(160)
Future income tax liabilities	**(81)**	(53)
Retained earnings	**(163)**	(107)
Total liabilities and shareholders' equity	**(244)**	(160)

Change in Consolidated Statements of Earnings

	Second quarter		Six months ended June 30	
($ millions, increase/(decrease))	**2006**	2005	**2006**	2005
Operating, selling and general	**77**	77	**159**	152
Depreciation, depletion and amortization	**(64)**	(31)	**(117)**	(59)
Future income taxes	**(3)**	(17)	**(13)**	(33)
Net earnings	**(10)**	(29)	**(29)**	(60)
Per common share – basic (dollars)	**(0.02)**	(0.06)	**(0.06)**	(0.13)
Per common share – diluted (dollars)	**(0.02)**	(0.06)	**(0.06)**	(0.13)

(b) Non-monetary Transactions

On January 1, 2006, the company prospectively adopted CICA Handbook section 3831 "Non-monetary Transactions". The standard requires all non-monetary transactions to be measured at fair value (if determinable) unless future cash flows are not expected to change significantly as a result of a transaction or the transaction is an exchange of a product held for sale in the ordinary course of business. The company was required to record the effects of an existing contract at Oil Sands that exchanges off-gas produced as a by-product of the upgrading operations for natural gas. An equal amount of revenues for the sale of the off-gas and purchases of crude oil and products for the purchase of the natural gas are recorded. The amount of the gross-up of revenues and purchases of crude oil and products for the three and six month periods ending June 30, 2006 was $31 million and $79 million respectively.

3. ENERGY MARKETING AND TRADING ACTIVITIES

The company uses physical and financial energy contracts, including swaps, forwards and options to gain market information and 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. The results of these activities are reported as revenue and as energy marketing and trading expenses in the Consolidated Statements of Earnings.

Physical energy marketing contracts involve activities intended to enhance prices and satisfy physical deliveries to customers. For the quarter ended June 30, 2006, these activities resulted in net pretax earnings of $6 million (2005 – pretax earnings of $7 million). For the six months ended June 30, 2006, physical energy marketing contracts resulted in net pretax earnings of $16 million (2005 – pretax earnings of $9 million).

In addition to the financial derivatives used for hedging activities, the company also enters into various financial energy contracts for trading activities. The following information presents all positions for the financial instruments only. For the quarter ended June 30, 2006, net pretax earnings of $nil (2005 – pretax loss of $1 million) resulted from the settlement and revaluation of the financial energy contracts. For the six months ended June 30, 2006 a net pretax loss of $1 million (2005 – pretax earnings of $1 million) was recorded. The above amounts do not include the impact of related general and administrative costs.

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

($ millions)	**June 30 2006**	December 31 2005
Energy trading assets	**21**	82
Energy trading liabilities	**13**	70
Net energy trading assets	**8**	12

Change in Fair Value of Net Assets

($ millions)	**2006**
Fair value of contracts outstanding at December 31, 2005	12
Fair value of contracts realized during 2006	**(4)**
Fair value of contracts entered into during the period	**2**
Changes in values attributable to market price and other market changes	**(2)**
Fair value of contracts outstanding at June 30, 2006	**8**

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

4. FINANCING EXPENSES (INCOME)

	Second quarter		Six months ended June 30	
($ millions)	**2006**	2005	**2006**	2005
Interest on debt	**38**	38	**77**	71
Capitalized interest	**(31)**	(31)	**(64)**	(57)
Net interest expense	**7**	7	**13**	14
Foreign exchange loss (gain) on long-term debt	**(52)**	16	**(51)**	22
Other foreign exchange loss (gain)	**25**	(2)	**25**	(8)
Total financing expenses (income)	**(20)**	21	**(13)**	28

5. RECONCILIATION OF BASIC AND DILUTED EARNINGS PER COMMON SHARE

($ millions)	Second quarter 2006	2005	Six months ended June 30 2006	2005
Net earnings	**1 218**	83	**1 931**	150
(millions of common shares)				
Weighted-average number of common shares	**459**	456	**459**	455
Options issued under stock-based compensation plans	**12**	10	**12**	11
Weighted-average number of diluted common shares	**471**	466	**471**	466
(dollars per common share)				
Basic earnings per share [a]	**2.65**	0.18	**4.21**	0.33
Diluted earnings per share [b]	**2.59**	0.18	**4.10**	0.32

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.

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

(a) Stock Option Plans

Under the SunShare long-term incentive plan, the company granted 338,000 options to new employees in the second quarter of 2006, for a total of 598,000 options granted in the six months ended June 30, 2006 (413,000 options granted during the second quarter of 2005; 677,000 options granted in the six months ended June 30, 2005).

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 criteria is not met, the unvested options that have not previously expired or been cancelled, will automatically vest on January 1, 2012.

Under the company's other plans, 62,000 options were granted in the second quarter of 2006, for a total of 1,571,000 options granted in the six months ended June 30, 2006 (64,000 options granted during the second quarter of 2005; 1,355,000 granted in the six months ended June 30, 2005).

The fair values of all common share options granted during the period are estimated as at the grant date using the Black-Scholes option-pricing model. 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:

	Second quarter 2006	2005	Six months ended June 30 2006	2005
Quarterly dividend per share	**$0.08**	$0.06	**$0.08***	$0.06
Risk-free interest rate	**4.25%**	3.59%	**4.11%**	3.73%
Expected life	**5 years**	5 years	**6 years**	6 years
Expected volatility	**29%**	28%	**29%**	28%
Weighted-average fair value per option	**$28.32**	$14.76	**$31.57**	$14.09

* 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 quarter.

Stock-based compensation expense recognized in the second quarter of 2006 related to stock options plans was $10 million (2005 – $6 million). For the six months ended June 30, 2006 stock-based compensation expense recognized was $19 million (2005 – $10 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)	Second quarter 2006	Second quarter 2005	Six months ended June 30 2006	Six months ended June 30 2005
Net earnings – as reported	**1 218**	83	**1 931**	150
Less: compensation cost under the fair value method for pre-2003 options	**3**	7	**5**	9
Pro forma net earnings	**1 215**	76	**1 926**	141
Basic earnings per share				
As reported	**2.65**	0.18	**4.21**	0.33
Pro forma	**2.65**	0.17	**4.20**	0.31
Diluted earnings per share				
As reported	**2.59**	0.18	**4.10**	0.32
Pro forma	**2.58**	0.16	**4.09**	0.30

(b) Performance Share Units (PSUs)

In the second quarter of 2006 the company issued 2,000 PSUs (2005 – 9,000). For the six months ended June 30, 2006, the company issued 392,000 PSUs (2005 – 445,000). Expense recognized in the second quarter of 2006 was $11 million (2005 – $5 million). Expense recognized for the six months ended June 30, 2006 was $35 million (2005 – $8 million).

7. EMPLOYEE FUTURE BENEFITS LIABILITY

The company's pension plans and other post-retirement benefits programs are described in note 8 of the company's 2005 Annual Report. The following is the status of the net periodic benefit cost for the quarter and six months ended June 30.

	Pension Benefits			
($ millions)	Second quarter 2006	Second quarter 2005	Six months ended June 30 2006	Six months ended June 30 2005
Current service costs	**11**	8	**22**	16
Interest costs	**10**	9	**20**	19
Expected return on plan assets	**(8)**	(7)	**(16)**	(14)
Amortization of net actuarial loss	**7**	6	**14**	11
Net periodic benefit cost	**20**	16	**40**	32

	Other Post-retirement Benefits			
($ millions)	Second quarter 2006	Second quarter 2005	Six months ended June 30 2006	Six months ended June 30 2005
Current service costs	**2**	1	**3**	3
Interest costs	**2**	2	**4**	4
Net periodic benefit cost	**4**	3	**7**	7

8. SUPPLEMENTAL INFORMATION

($ millions)	Second quarter 2006	Second quarter 2005	Six months ended June 30 2006	Six months ended June 30 2005
Interest paid	**22**	23	**75**	69
Income taxes paid	**6**	21	**17**	55

Revenue Hedges

Strategic Crude Oil at June 30, 2006

	Quantity (bpd)	Average Price (US$/bbl)[a]	Revenue Hedged (Cdn$ millions)[b]	Hedge Period[c]
Costless collars	50 000	50.00 – 91.70	513 – 941	2006
Costless collars	50 000	50.00 – 91.70	1 017 – 1 866	2007

Natural Gas at June 30, 2006

	Quantity (GJ/day)	Average Price (Cdn$/GJ)	Revenue Hedged (Cdn$ millions)	Hedge Period[c]
Swaps	4 000	6.58	5	2006
Costless collars	10 000	8.75 – 13.38	11 – 16	2006 [d]
Swaps	4 000	6.11	9	2007

Foreign Currency Hedges at June 30, 2006

	Notional (Euro millions)	Average Forward Rate	Dollars Hedged (Cdn$ millions)	Hedge Period
Euro/Cdn forward	20.6	1.40	29	2007 [e]

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

(b) The revenue hedged is translated to Cdn$ at the June 30, 2006 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 July to October 2006, inclusive.

(e) Settlements for applicable forwards occurring within the period April to September 2007.

9. INCOME TAXES

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.

10. ROYALTY ESTIMATE MEASUREMENT UNCERTAINTY

Alberta Crown royalties 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. Firebag is being treated by the Government of Alberta as a separate project from the rest of the Oil Sands operations for royalty purposes.

In February 2006, we advised the Government of Alberta we would not proceed with a July 2004 claim we filed against the Crown where we were seeking to overturn the government's decision on the royalty treatment of our Firebag in-situ operations.

Oil Sands royalties payable in 2006 are highly sensitive to, among other factors, changes in crude oil and natural gas pricing, timing of the receipt of property damage insurance proceeds, foreign exchange rates and total capital and operating costs for each project. Oil Sands pretax royalty estimate was $563 million ($373 million after tax) for the first six months of 2006 compared to $181 million ($110 million after tax) for the first six months of 2005. We estimate 2006 annualized oil sands royalties to be approximately $1,019 million ($675 million after tax) based on six months of actual results including the final $385 million in business interruption insurance proceeds, together with 2006 forward crude oil pricing of US$75.21 as at June 30, 2006, current forecasts of production, capital and operating costs for the remainder of 2006, a Canadian/US foreign exchange rate of $0.90, and no further receipts of property loss insurance proceeds other than those recorded to date. Accordingly, actual results will differ, and these differences may be material. The balance of the royalty expense is in respect of natural gas royalties of $65 million ($43 million after tax).

11. CREDIT FACILITIES

During the second quarter, a $1.5 billion credit facility agreement was renegotiated and extended by two years, to have a five year term maturing in June 2011. The credit limit of this facility was also increased by $500 million to $2 billion. In addition, a $200 million credit facility agreement was renegotiated and increased by $100 million to $300 million. As well, a $600 million credit facility agreement matured during the second quarter and was not renewed. At June 30, 2006, the company had available facilities as follows:

($ millions)	
Facility that is fully revolving for 364 days, has a term period of one year and expires in 2008	300
Facility that is fully revolving for a period of five years and expires in 2011	2 000
Facilities that can be terminated at any time at the option of the lenders	30
Total available credit facilities	2 330

As at June 30, 2006, undrawn lines of credit were approximately $1,820 million.

HIGHLIGHTS

(unaudited)

	2006	2005
Cash Flow from Operations		
(dollars per common share)		
For the three months ended June 30		
Cash flow from operations (1)	**2.88**	0.67
For the six months ended June 30		
Cash flow from operations (1)	**5.74**	1.32
Ratios		
For the twelve months ended June 30		
Return on capital employed (%) (2)	**43.9**	12.9
Return on capital employed (%) (3)	**32.0**	10.3
Net debt to cash flow from operations (times) (4)	**0.5**	1.7
Interest coverage on long-term debt (times)		
Net earnings (5)	**24.8**	9.3
Cash flow from operations (6)	**28.8**	13.0
As at June 30		
Debt to debt plus shareholders' equity (%) (7)	**23.0**	36.8
Common Share Information		
As at June 30		
Share price at end of trading		
Toronto Stock Exchange – Cdn$	**90.34**	57.92
New York Stock Exchange – US$	**81.01**	47.32
Common share options outstanding (thousands)	**19 610**	19 630
For the six months ended June 30		
Average number outstanding, weighted monthly (thousands)	**458 596**	455 486

Refer to the Quarterly Operating Summary for a discussion of financial measures not prepared in accordance with 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) Net earnings (2006 – $2,883 million; 2005 – $814 million) adjusted for after-tax financing expenses (2006 – income of $56 million; 2005 – income of $60 million) for the twelve month period ended; divided by average capital employed (2006 – $6,573 million; 2005 – $5,834 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 56 of Suncor's 2005 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: 2006 – $8,997 million; 2005 – $7,322 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					Six months ended		Total year
	June 30 2006	Mar 31 2006	Dec 31 2005	Sep 30 2005	June 30 2005	**June 30 2006**	June 30 2005	Dec 31 2005
OIL SANDS								
Production (1),(a)								
Total production	**267.3**	264.4	267.7	148.2	128.2	**266.0**	134.1	171.3
Firebag	**35.0**	27.4	26.0	23.0	8.7	**31.3**	13.7	19.1
Sales (a)								
Light sweet crude oil	**124.7**	119.2	108.6	69.9	48.3	**121.9**	61.8	73.3
Diesel	**32.9**	35.1	30.7	10.6	9.0	**34.1**	10.4	15.6
Light sour crude oil	**99.2**	121	104.2	41.7	54.2	**110.0**	46.4	59.8
Bitumen	**8.5**	—	7.2	22.3	9.6	**4.3**	13.9	16.6
Total sales	**265.3**	275.3	250.7	144.5	121.1	**270.3**	132.5	165.3
Average sales price (2),(b)								
Light sweet crude oil	**78.27**	69.00	55.96	52.08	39.20	**73.76**	42.80	49.93
Other (diesel, light sour crude oil and bitumen)	**72.75**	63.28	63.84	59.70	50.47	**67.80**	48.80	56.90
Total	**75.34**	65.75	60.42	56.01	45.98	**70.49**	46.23	53.81
Total *	**75.34**	65.75	66.68	67.95	57.24	**70.49**	55.92	62.68
CASH OPERATING COSTS AND TOTAL OPERATING COSTS – TOTAL OPERATIONS								
Cash costs	**15.65**	15.55	16.20	21.65	23.50	**15.60**	21.95	19.60
Natural gas	**2.55**	3.45	4.65	6.00	3.60	**3.00**	4.55	4.90
Imported bitumen	**0.10**	0.05	0.05	—	—	**0.05**	0.05	0.05
Cash operating costs (3),(c)	**18.30**	19.05	20.90	27.65	27.10	**18.65**	26.55	24.55
Firebag start-up costs	**—**	0.90	0.30	—	—	**0.45**	—	0.10
Total cash operating costs (4),(c)	**18.30**	19.95	21.20	27.65	27.10	**19.10**	26.55	24.65
Depreciation, depletion and amortization	**3.80**	3.90	3.60	6.10	6.75	**3.85**	6.50	5.30
Total operating costs (5),(c)	**22.10**	23.85	24.80	33.75	33.85	**22.95**	33.05	29.95
CASH OPERATING COSTS AND TOTAL OPERATING COSTS – IN-SITU BITUMEN PRODUCTION								
Cash costs	**8.50**	14.20	6.70	7.55	21.50	**10.95**	12.90	9.15
Natural gas	**8.15**	7.70	13.80	13.25	16.40	**7.95**	12.10	13.05
Cash operating costs (6),(c)	**16.65**	21.90	20.50	20.80	37.90	**18.90**	25.00	22.20
Depreciation, depletion and amortization	**3.75**	6.90	4.60	4.25	7.60	**5.10**	5.65	4.90
Total operating costs (7),(c)	**20.40**	28.80	25.10	25.05	45.50	**24.00**	30.65	27.10
(for the period ended)								
Capital employed (h)	**5 544**	5 450	4 472	4 334	4 173			
(for the twelve months ended)								
Return on capital employed (i)	**53.8**	35.5	22.7	15.1	15.7			
Return on capital employed (i) ****	**40.5**	26.3	16.3	11.2	12.2			

QUARTERLY OPERATING SUMMARY (continued)

(unaudited)

	For the quarter ended					Six months ended		Total year
	June 30 2006	Mar 31 2006	Dec 31 2005	Sep 30 2005	June 30 2005	**June 30 2006**	June 30 2005	Dec 31 2005
NATURAL GAS								
Gross production **								
Natural gas (d)	**189**	196	193	200	175	**193**	183	190
Natural gas liquids (a)	**2.6**	2.4	2.3	2.2	2.2	**2.5**	2.6	2.4
Crude oil (a)	**0.9**	0.8	0.6	0.7	1.0	**0.9**	0.9	0.8
Total gross production (e)	**35.1**	35.9	35.0	36.3	32.4	**35.5**	34.0	34.8
Average sales price (2)								
Natural gas (f)	**6.38**	9.03	11.66	8.32	7.29	**7.73**	7.04	8.57
Natural gas (f) *	**6.22**	8.75	11.83	8.34	7.26	**7.51**	6.99	8.59
Natural gas liquids (b)	**60.14**	51.75	57.85	58.00	52.52	**56.19**	44.38	50.70
Crude oil – Conventional (b)	**74.18**	60.30	72.60	63.77	63.86	**67.81**	62.68	64.85
Net wells drilled								
Conventional – Exploratory ***	**1**	5	3	4	0	**6**	5	12
– Development	**2**	4	13	2	2	**6**	7	22
	3	9	16	6	2	**12**	12	34
(for the period ended)								
Capital employed (h)	**770**	590	563	598	564			
(for the twelve months ended)								
Return on capital employed (i)	**30.6**	31.7	30.7	22.7	22.5			
ENERGY MARKETING AND REFINING – CANADA								
Refined product sales (g)								
Transportation fuels								
Gasoline								
Retail	**4.6**	4.4	4.5	4.2	4.8	**4.5**	4.7	4.5
Other	**3.9**	3.6	3.3	4.2	4.1	**3.7**	4.0	3.9
Jet fuel	**0.8**	0.7	0.8	0.9	0.8	**0.7**	0.9	0.9
Diesel	**3.5**	3.2	3.4	3.7	3.3	**3.4**	3.0	3.3
Total transportation fuel sales	**12.8**	11.9	12.0	13.0	13.0	**12.3**	12.6	12.6
Petrochemicals	**0.9**	1.2	0.4	0.7	0.8	**1.1**	0.8	0.7
Heating oils	**0.4**	0.6	0.5	0.2	0.3	**0.5**	0.5	0.4
Heavy fuel oils	**0.7**	0.9	0.9	0.8	1.4	**0.8**	1.2	1.0
Other	**0.6**	0.7	0.5	0.9	0.6	**0.6**	0.5	0.5
Total refined product sales	**15.4**	15.3	14.3	15.6	16.1	**15.3**	15.6	15.2
Crude oil supply and refining								
Processed at Sarnia refinery (g)	**9.9**	9.6	10.6	10.7	11.1	**9.7**	10.6	10.6
Utilization of refining capacity (i)	**89**	86	95	96	100	**87**	95	95
(for the period ended)								
Capital employed (h)	**490**	535	486	547	507			
(for the twelve months ended)								
Return on capital employed (i)	**23.9**	11.5	8.1	7.7	10.1			
Return on capital employed (i) ****	**12.4**	6.8	5.2	5.6	8.1			

QUARTERLY OPERATING SUMMARY (continued)

(unaudited)

	For the quarter ended					Six months ended		Total year
	June 30 2006	Mar 31 2006	Dec 31 2005	Sept 30 2005	Jun 30 2005	**June 30 2006**	June 30 2005	Dec 31 2005
REFINING AND MARKETING – U.S.A.								
Refined product sales (g)								
Transportation fuels								
Gasoline								
Retail	**0.7**	0.7	0.7	0.7	0.7	**0.7**	0.7	0.7
Other	**8.0**	5.3	7.1	8.9	5.0	**6.3**	4.4	6.2
Jet fuel	**0.9**	0.8	0.9	0.8	0.7	**0.8**	0.7	0.8
Diesel	**3.8**	3.2	3.6	3.9	3.1	**3.5**	2.9	3.3
Total transportation fuel sales	**13.4**	10.0	12.3	14.3	9.5	**11.3**	8.7	11.0
Asphalt	**1.3**	1.0	1.2	1.8	1.9	**1.1**	1.8	1.6
Other	**1.5**	0.3	1.0	1.2	1.2	**1.1**	1.0	1.1
Total refined product sales	**16.2**	11.3	14.5	17.3	12.6	**13.5**	11.5	13.7
Crude oil supply and refining								
Processed at Denver refinery (g)	**14.6**	9.2	13.0	14.9	11.4	**11.9**	10.3	12.1
Utilization of refining capacity (i)	**102**	65	91	104	102	**83**	100	98
(for the period ended)								
Capital employed (h)	**340**	341	327	354	349			
(for the twelve months ended)								
Return on capital employed (i)	**45.7**	42.2	49.4	32.2	17.6			
Return on capital employed (i) ****	**23.1**	22.7	28.9	21.6	13.8			

QUARTERLY OPERATING SUMMARY (continued)

Non-GAAP Financial Measures

Certain financial measures referred to in the Highlights and Quarterly Operating Summary are not prescribed by 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 production volumes that are processed through the upgrader facilities. 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 for in-situ operations. Per barrel amounts are based on all production volumes that are processed through the upgrader facilities.
(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 all production volumes that are processed through the upgrader facilities.
(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.
(7) Total operating costs – In-situ bitumen production	- Include cash operating costs – Firebag as defined above and non-cash operating costs. Per barrel amounts are based on in-situ production volumes.

Explanatory Notes

* Excludes the impact of hedging activities.

** Currently all 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) dollars per thousand cubic feet
(g) thousands of cubic metres per day
(h) $ millions
(i) percentage

Metric Conversion

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