first quarter 2006

Report to shareholders for the period ended March 31, 2006

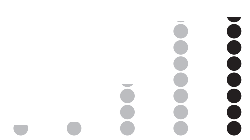
> growing strategically

Suncor Energy's first quarter results set the stage for strong 2006 performance

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 first quarter management's discussion and analysis. This document makes reference to barrels of oil equivalent (boe). A boe conversion ratio of six thousand cubic feet of natural gas: one barrel of crude oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Accordingly, boe measures may be misleading, particularly if used in isolation.

Suncor Energy Inc. recorded first quarter 2006 net earnings of $713 million ($1.56 per common share), compared to $67 million ($0.15 per common share) in the first quarter of 2005. Excluding the impact of insurance proceeds and the effects of unrealized foreign exchange gains on the company's U.S. dollar denominated long-term debt, 2006 first quarter net earnings were $509 million ($1.11 per common share), compared to $40 million ($0.09 per common share) in the first quarter of 2005. Cash flow from operations was $1.314 billion in the first quarter of 2006, compared to $294 million in the first quarter of 2005.

Earnings by Quarter
($ millions)

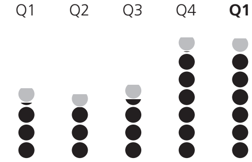


	2005 Q1	2005 Q2	2005 Q3	2005 Q4	**2006 Q1**
	67	83	315	693	**713**

Cash Flow from Operations by Quarter
($ millions)

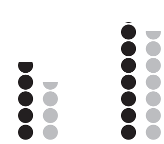
	2005 Q1	2005 Q2	2005 Q3	2005 Q4	**2006 Q1**
	294	305	651	1 226	**1 314**

Production
(thousands of barrels of oil equivalent per day)



	2005 Q1	2005 Q2	2005 Q3	2005 Q4	**2006 Q1**
Natural Gas	35.7	32.4	36.3	35.0	**35.9**
Oil Sands	139.9	128.2	148.2	267.7	**264.4**
Total	175.6	160.6	184.5	302.7	**300.3**

Ratios
(per cent)
for the twelve months ended March 31



	2005	**2006**
Return on average shareholder's equity	20.5	**30.9**
Return on capital employed	15.1	**28.5**

The increase in net earnings was due to higher oil sands production, higher commodity prices and receipt of fire insurance proceeds. These positive impacts were partially offset by higher oil sands operating costs as a result of increased production volumes, as well as higher royalties expense and higher stock-based compensation expense. The same factors impacted cash flow from operations.

Suncor's total upstream production averaged 300,300 barrels of oil equivalent (boe) per day during the first quarter, compared to 175,600 boe per day in the first quarter of 2005. Oil sands production during the quarter averaged 264,400 barrels per day (bpd), of synthetic crude oil. This compares to the first quarter of 2005, when production averaged 139,900 bpd, including 18,700 bpd of non-upgraded bitumen production.

Natural gas production in the first quarter of 2006 was 196 million cubic feet (mmcf) per day, compared to first quarter 2005 production of 191 mmcf per day.

During the first quarter, oil sands cash operating costs averaged $19.05 per barrel, compared to $26.05 per barrel during the first quarter of 2005. The decrease in cash operating costs per barrel is primarily due to operating expenses being spread over significantly more barrels of production. (For information on adjustments to cash operating cost calculations, see Outlook for 2006).

A planned maintenance shutdown at Suncor's Denver refinery reduced utilization to 65% in the first quarter of 2006 from 96% in the first quarter of 2005, impacting earnings. Earnings at the company's Sarnia refinery were also impacted by reduced utilization due to unplanned maintenance. Utilization was 86% in the first quarter of 2006, compared to 91% in the first quarter of 2005.

"With solid first quarter production, the stage is set for a strong year," said Rick George, president and chief executive officer. "The goal now is to maintain steady, full capacity production across our operations and deliver on our strategic growth priorities."

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 about 35% 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 by about 35%, also includes addition of cogeneration facilities. This project is also on schedule and on budget.

A regulatory hearing will begin July 5, 2006 on Suncor's planned third upgrader. The upgrader 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.

Modifications to the Denver refinery remain on schedule with tie-in of new facilities expected in the second quarter, but cost estimates have increased to $540 million (US$445 million) from the original estimate of $360 million (US$300 million). Modifications to the Sarnia refinery remain within budget, however work on the diesel desulphurization portion of the project is expected to continue past the original June 1, 2006 target for completion. Suncor is taking steps to mitigate the impact of the schedule revision on diesel desulphurization regulatory requirements.

"While our oil sands expansion plans remain on budget and on schedule, the challenges we are seeing in our downstream projects underline the seriousness of inflationary pressures and labour supply issues across our business," said George.

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 levels were relatively stable at $2.8 billion at the end of the first quarter, compared with $2.9 billion at the end of 2005.

"With solid first quarter production, the stage is set for a strong year. The goal now is to maintain steady, full capacity production across our operations and deliver on our strategic growth priorities." **Rick George** president and chief executive officer

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.

	Three months ended March 31, 2006	2006 Full Year Outlook
Oil Sands		
Production (bpd) (1)	**264 400**	260 000
Diesel (2)	**13%**	11%
Sweet (2)	**43%**	45%
Sour (2)	**44%**	44%
Realization on crude sales basket	**WTI @ Cushing less Cdn$7.25 per barrel**	WTI @ Cushing less Cdn$5.50 to $6.50 per barrel
Cash operating costs (3)	**$19.05 per barrel**	$18.75 to $19.50 per barrel
Natural Gas		
Natural gas (mmcf/d)	**196**	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.

(2) Suncor is still gaining experience in operating facilities that were newly commissioned in late 2005. As a result, there is more uncertainty in providing 2006 targets than in previous years, especially as it relates to sour crude volumes.

(3) 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 12 of Suncor's first quarter 2006 Management's Discussion and Analysis). 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 previously reported 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 the first quarter 2006 Report 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 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".

Factors that could potentially impact Suncor's financial performance in 2006 include:

- Crude oil hedges. As at March 31, 2006, crude oil hedges totalling 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.
- Planned maintenance work and tie-in of modified facilities at Suncor's refining operations. Should the work take longer than planned or be impacted by labour or material supply issues, capital costs and refined product sales could be impacted.

For a discussion of risks and uncertainties that may affect our financial performance, see page 14.

MANAGEMENT'S DISCUSSION AND ANALYSIS

May 2, 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 14 for additional information.

This MD&A should be read in conjunction with our March 31, 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 our 2005 Annual Information Form. All financial information is reported in Canadian dollars (Cdn$) and in accordance with Canadian generally accepted accounting principles (GAAP) unless noted otherwise. The financial measures cash flow from operations, return on capital employed (ROCE) and cash and total operating costs per barrel referred to in this MD&A are not prescribed by GAAP and are described and reconciled in "Non-GAAP Financial Measures" on page 56 of our Annual Report, and page 13 of this MD&A.

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

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

References to "we," "our," "us," "Suncor," or "the company" mean Suncor Energy Inc., its subsidiaries, partnerships and joint venture investments, unless the context 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, 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 projects that, in many cases, are still in the early stages of development. These costs are preliminary estimates only. The actual amounts are expected to differ and these differences may be material. For a further discussion of our significant capital projects and the range of cost estimates associated with an "on-budget" project, see the "Significant Capital Project Update" on page 11.

SELECTED FINANCIAL INFORMATION

Industry Indicators

($ average for the period) 3 months ended March 31 (Q1)	**2006**	2005
West Texas Intermediate (WTI) crude oil US$/barrel at Cushing	**63.50**	49.85
Canadian 0.3% par crude oil Cdn$/barrel at Edmonton	**69.10**	61.95
Light/heavy crude oil differential US$/barrel WTI Cushing less Lloydminster Blend at Hardisty	**29.00**	19.25
Natural Gas US$/mcf at Henry Hub	**9.05**	6.30
Natural Gas (Alberta spot) Cdn$/mcf at AECO	**9.25**	6.70
New York Harbour 3-2-1 crack (1) US$/barrel	**7.10**	6.00
Exchange rate: Cdn$:US$	**0.87**	0.82

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

Outstanding Share Data (as at March 31, 2006)

Common shares	458 713 655
Common share options – total	19 808 707
Common share options – exercisable (1)	9 632 762

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

Summary of Quarterly Results

($ millions, except per share data)	**2006 quarter ended** Mar. 31	2005 quarter ended Dec. 31	Sept. 30	June 30	Mar. 31	2004 quarter ended Dec. 31	Sept. 30	June 30
Revenues	**3 858**	3 521	3 149	2 385	2 074	2 333	2 332	2 219
Net earnings	**713**	693	315	83	67	326	338	196
Net earnings attributable to common shareholders per share								
Basic	**1.56**	1.52	0.69	0.18	0.15	0.72	0.75	0.43
Diluted	**1.52**	1.48	0.67	0.18	0.14	0.71	0.73	0.43

ANALYSIS OF CONSOLIDATED STATEMENTS OF EARNINGS AND CASH FLOWS

Net earnings for the first quarter of 2006 were $713 million, compared to $67 million for the first quarter of 2005. The increase in net earnings was primarily due to:

- an increase in Oil Sands crude oil production following recovery work to repair portions of the plant damaged in a January 2005 fire and the subsequent expansion of production capacity to 260,000 barrels per day (bpd) completed in October 2005
- an increase in the average price realization for Oil Sands crude oil to $65.75 per barrel in the first quarter of 2006 from $46.44 per barrel during the first quarter of 2005. The price increase reflects:

  i) a 27% increase in the average U.S. dollar denominated benchmark WTI crude oil prices
  ii) absence of hedging losses on crude oil swaps (see "Derivative Financial Instruments" on page 11)

  partially offset by:

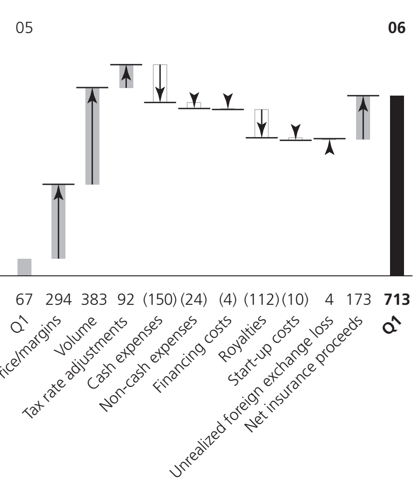
  i) a lower sales mix of high value products
  ii) widening light/heavy differentials
  iii) a 6% strengthening of the Canadian dollar compared to the U.S. dollar (the stronger Canadian dollar reduces the realized value of Suncor's products)
- final settlement of our business interruption claim related to the January 2005 fire, which increased first quarter of 2006 net earnings by $173 million compared to the first quarter of 2005 (see page 7)
- lower effective tax rate (see below)
- higher refining margins in our Canadian downstream operations
- higher earnings in our Natural Gas business reflecting higher natural gas prices

These positive impacts were partially offset by higher Oil Sands operating costs as a result of increased production volumes, as well as higher royalty expense and higher stock-based compensation expense.

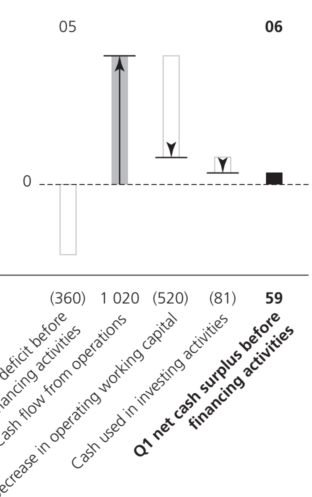
Cash flow from operations was $1,314 million in the first quarter of 2006 compared to $294 million in the same period of 2005. The same factors impacting net earnings contributed to higher cash flow from operations.

Our effective tax rate for the first quarter of 2006 was 37% compared to 47% in the first quarter of 2005. The first quarter 2006 effective tax rate is consistent with our expectations. The higher effective tax rate in the first quarter of 2005 was due to the proportionately lower Oil Sands earnings relative to consolidated earnings. As a result, earnings subject to a higher effective tax rate (our Natural Gas business), 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)



NET EARNINGS COMPONENTS

This table explains the material 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.

($ millions, after tax)	**Q1 2006**	Q1 2005
Net earnings before the following items	**522**	40
Firebag Stage 2 start-up costs	**(13)**	—
Unrealized foreign exchange gain/loss on U.S. dollar denominated debt	**(1)**	(5)
Oil Sands fire accrued insurance proceeds (1)	**205**	32
Net earnings as reported	**713**	67

(1) Accrued business interruption proceeds of $385 million (US$330 million) net of income taxes and Alberta Crown royalties. For discussion see pages 7 and 8.

ANALYSIS OF SEGMENTED EARNINGS AND CASH FLOW

Oil Sands

Oil Sands recorded 2006 first quarter net earnings of $720 million, compared with $83 million in the first quarter of 2005. Net earnings were higher primarily as a result of a more than 85% increase in production and sales volumes reflecting the September 2005 return to operations of facilities damaged in the January 2005 fire and the subsequent expansion of upgrading capacity to 260,000 bpd in October 2005. Earnings were also positively impacted by:

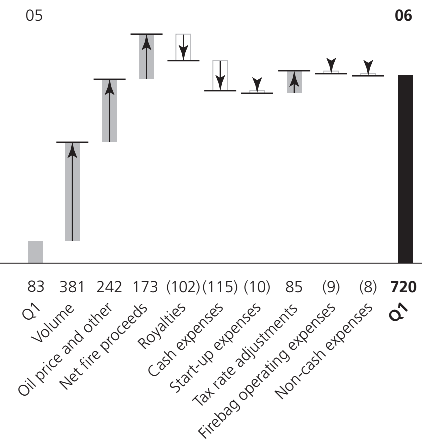
- the final settlement of our business interruption insurance claim for $385 million (US$330 million) resulted in increased earnings of $173 million
- an increase in the average realization of Oil Sands crude products, primarily reflecting a 27% increase in average benchmark WTI crude oil prices, and the absence of crude oil hedging losses in the first quarter of 2006

These positive impacts were partially offset by the 6% 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 $508 million in the first quarter of 2006 compared to $321 million in the first quarter of 2005, primarily due to the following factors:

- higher total production levels
- increased costs at our in-situ operations related to the start-up of Firebag Stage 2 commercial operations
- higher energy costs as a result of:
  i) higher natural gas costs as a result of higher benchmark natural gas prices
  ii) increased consumption of natural gas at our base plant
  iii) a change in accounting policy for non-monetary transactions (see page 12) whereby certain natural gas costs and offsetting revenues of $48 million were recorded in the first quarter of 2006

Bridge Analysis of Net Earnings
($ millions)



- costs related to constructing a new tailings pond
- 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 self-insurance entity (see page 10)

Transportation and other costs were $37 million in the first quarter of 2006 compared to $24 million in the first quarter of 2005. Increased transportation costs are due primarily to increased shipped volumes out of the Fort McMurray area.

Depreciation, depletion and amortization expense was $93 million in the first quarter of 2006 compared to $79 million during the same period in 2005. The increase is due primarily to the inclusion of newly commissioned upgrading facilities and Firebag Stage 2 operations in our depreciable cost base.

Alberta Crown royalty expense was $285 million in the first quarter of 2006 compared to $87 million in the first quarter of 2005. The increase was due to higher commodity prices and sales volumes, higher net fire insurance proceeds, partially offset by higher operating costs and capital cost deductions. See page 8 for a discussion of Alberta Oil Sands Crown royalties.

Project start-up costs for the first quarter of 2006 were $21 million compared to $3 million in the first quarter of 2005. This increase is due primarily to our Firebag Stage 2, which commenced commercial operations in early March 2006.

Cash flow from operations was $1,209 million in the first quarter of 2006, compared to $248 million in the first quarter of 2005. Excluding the impact of depreciation, depletion and amortization, the increase was primarily due to the same factors that impacted net earnings.

Oil Sands production during the first quarter of 2006 averaged 264,400 bpd of upgraded crude oil, compared to production of 139,900 bpd (including 18,700 bpd of bitumen production sold directly to the market) during the first quarter of 2005. The increase in production volumes was due to the completion of fire damage repairs to our upgrader and subsequent commissioning of facilities that increased production capacity. As a result of our increased upgrading capacity, all of our in-situ bitumen production in the first quarter of 2006 was upgraded before being sold to the market. In the first quarter of 2005, we sold all of our in-situ bitumen production directly to the market.

Sales during the first quarter of 2006 averaged 275,300 bpd, compared with 144,000 bpd during the first quarter of 2005. The proportion of higher value diesel fuel and sweet crude products decreased to 56% of the total sales in the first quarter of 2006, compared to 60% in the first quarter of 2005. Sales prices averaged $65.75 per barrel during the first quarter of 2006 compared to $46.44 per barrel in the first 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 12), 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, cash operating costs per barrel 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 (mining and upgrading) operations and in-situ operations were disclosed separately. All comparative balances have been retroactively restated for these changes in the first quarter 2006 Report to Shareholders.

During the first quarter, cash operating costs averaged $19.05 per barrel, compared to $26.05 per barrel during the first 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 following recovery work to repair plant facilities damaged in the January 2005 fire and subsequent facility expansion. Refer to page 13 for further details on cash operating costs as a non-GAAP financial measure, including the calculation and reconciliation to GAAP measures.

Oil Sands Fire Insurance Update

On January 4, 2005, a fire damaged Upgrader 2 reducing production from base operations. In September 2005, repairs to the damaged components were completed and Oil Sands base operations returned to full production capacity.

Suncor carries property loss and business interruption (BI) insurance policies with a combined coverage limit of US$1.15 billion. For a description of our insurance policy coverage and deductibles see page 24 of our Annual Report. In April 2006, we settled the business interruption claims arising from the fire. The final instalment of approximately $385 million (US$330 million) is receivable in the second quarter, and was accrued as net insurance proceeds in the first quarter of 2006. This final instalment is in addition to $594 million (US$500 million) in proceeds recorded in 2005 bringing total insurance proceeds to $979 million (US$830 million) out of the total BI insurance policies coverage (US$900 million). BI proceeds are treated in the same manner for royalty purposes as the revenues they replace and accordingly attract Alberta Crown royalties.

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. The cost to repair the damage caused by the fire did not exceed our primary property coverage. To date we have received $115 million (US$95 million) in proceeds from our property loss insurers. During the first quarter of 2006 we did not receive additional proceeds from the property loss policy. However, settlement of this policy is anticipated during 2006.

Oil Sands Growth Update

During the first quarter of 2006 work continued on our next major growth project to increase 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.

Work under way also includes the expansion of Suncor's Firebag in-situ operations, targeted for completion in 2009. The project, which is expected to increase the bitumen production capacity of Firebag Stages 1 and 2 by about 35%, also includes addition of cogeneration facilities. Both expansion projects are on schedule and on budget. For an update on our significant growth projects currently in progress see page 11.

In the first quarter of 2005, we filed an application with Alberta regulators to construct and operate a third oil sands upgrader, designed to increase production capacity to half a million barrels of oil per day. The regulatory hearings for this application are scheduled for the second quarter of 2006.

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 page 27 of our Annual Report.

For the first three months of 2006 we recorded a pretax royalty estimate of $285 million ($182 million after tax) compared to $87 million ($53 million after tax) for the first three months of 2005. We estimate 2006 annualized Crown Royalties to be approximately $950 million ($608 million after tax) based on three 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$69.02 as at March 31, 2006, current forecasts of production, capital and operating costs for the remainder of 2006, a Canadian/US foreign exchange rate of $0.88, 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. 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 and cash tax expense in the years 2006 through 2012, and certain assumptions on which we have based our estimates.

OUTLOOK ROYALTY AND CASH TAX EXPENSE BASED ON CERTAIN ASSUMPTIONS

(For the period from 2006-2012)

WTI Price/bbl (US$)	**40**	**50**	**60**
Natural gas price per mcf at Henry Hub (US$)	6.50	7.50	8.50
Light/heavy oil differential of WTI at Cushing less Maya at the U.S. Gulf Coast (US$)	9.50	10.50	12.00
Cdn$/US$ exchange rate	0.80	0.85	0.85
Crown royalty expense (based on percentage of total Oil Sands revenue) (%)			
2006-08	10-12	12-14	12-14
2009-12 (1)	5-7	6-8	6-8
Approximate cash tax (based on percentage of total tax expense) (%) (2)			
2007	50	40	30
2008 (3)	5	5	15
2009	5	25	30

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

(2) Cash tax expense in the first year is payable in February of the following year.

(3) Reduced rate due primarily to the completion of the Coker Unit expansion.

As with the estimate of 2006 Alberta Crown royalties, outlook royalty and cash tax expense 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 the government. 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 as a percentage of total tax expense, or the impact these royalties and cash taxes may have on our financial results. Actual differences may be material.

Using the assumptions outlined in the table above, we anticipate that our Oil Sands and NG operations will be partially cash taxable commencing in 2007. These operations will continue to be partially cash taxable until the next decade, at which point they are expected to become fully cash taxable. 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 tax purposes.

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 future events or circumstances.

Natural Gas

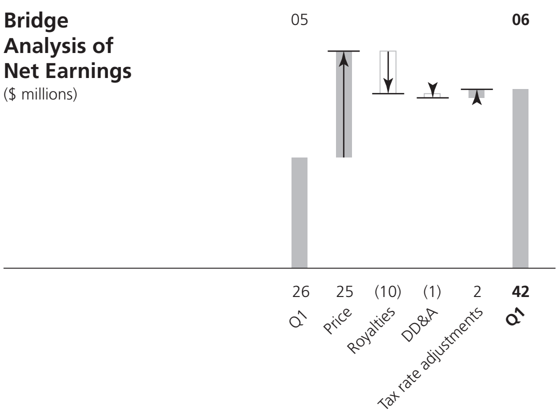
Natural Gas recorded 2006 first quarter net earnings of $42 million, compared to $26 million during the first quarter of 2005. The increase was due primarily to higher natural gas prices, partially offset by higher royalties and lifting costs. Realized natural gas prices in the first quarter of 2006 were $9.03 per thousand cubic feet (mcf) compared to $6.81 per mcf in the first quarter of 2005.

During the first quarter of 2006 we sold a 15% interest in the South Rosevear gas plant for proceeds of $12 million, resulting in an after-tax gain on disposition of $2.6 million.

Cash flow from operations for the first quarter of 2006 was $100 million compared to $83 million in the first quarter of 2005. The increase was primarily due to the same factors that increased net earnings.

Natural gas production in the first quarter of 2006 was 196 million cubic feet (mmcf) per day, compared to 191 mmcf per day in the first 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.

Bridge Analysis of Net Earnings
($ millions)



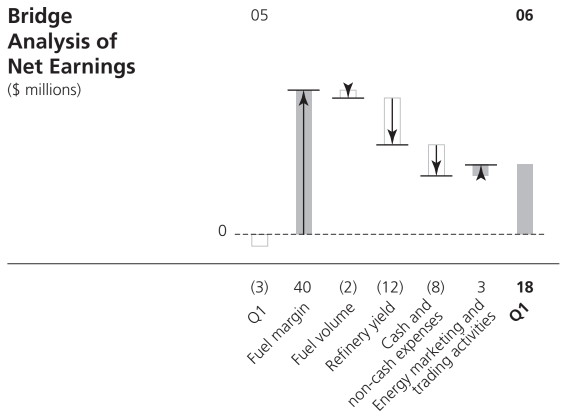
Energy Marketing & Refining – Canada

EM&R recorded 2006 first quarter net earnings of $18 million, compared to net losses of $3 million in the first quarter of 2005. The increase in net earnings was primarily due to higher refining margins partially offset by higher purchase costs for third party finished products. Refining margins in the first quarter of 2006 were impacted by favorable prices for crude oil feedstock purchased relative to WTI.

Energy marketing and trading activities, including physical trading activities, resulted in net earnings of $5 million in the first quarter of 2006, compared to net earnings of $2 million in the first quarter of 2005.

Cash flow from operations for the first quarter increased to $51 million from $22 million in the first quarter of 2005. The increase was primarily due to the same factors that increased net earnings.

Bridge Analysis of Net Earnings
($ millions)

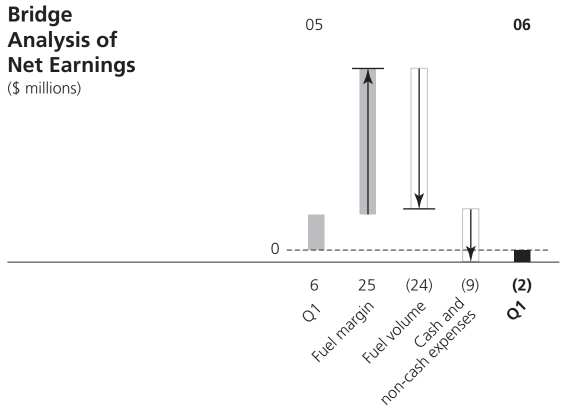


We have revised our diesel desulphurization project schedule outward from June 1, 2006. We are taking steps to mitigate the impact of the schedule revision on diesel desulphurization regulatory requirements. For an update of our significant capital projects in progress see page 11.

Refining & Marketing – U.S.A.

Refining & Marketing – U.S.A. (R&M) recorded a net loss of $2 million in the first quarter of 2006 compared to net earnings of $6 million during the first quarter of 2005. Net earnings in 2006 were negatively impacted by the planned maintenance shutdown of the West refinery that resulted in reduced refinery utilization, and required additional higher cost finished product purchases to meet customer demand. The scheduled shutdown was completed in early April 2006, slightly behind schedule. Partially offsetting these factors were increased sales volumes and improved refinery margins. In addition to the increased finished product purchases, the increase in sales was achieved through additional production from the East plant acquired from Valero in May 2005 and a temporary drawdown of inventory.

Bridge Analysis of Net Earnings
($ millions)



Cash flow from operations for the first quarter of 2006 was $Nil compared to $18 million in the first quarter of 2005. Cash flow from operations decreased due to the same factors that decreased net earnings.

Suncor's diesel desulphurization and oil sands integration project at the Denver refinery is on schedule. During the maintenance shutdown, the refinery also began commissioning a portion of the project and also installed equipment to reduce refinery emissions. The remaining portions are anticipated to come online during the second quarter of 2006. However, labour shortages and material supply issues continue to result in cost pressures. The project budget of US$390 million (revised from the original US$300 million) has been increased to a final expected cost of US$445 million. See page 11 for an update on our significant capital projects in progress.

In February 2006, a three-year labour agreement was reached with the local unions representing our refinery employees at our East and West plants. The employees now fall under one collective bargaining agreement that expires in January 2009. This is a significant step in aligning our resources for the integration and optimization of our U.S. downstream operations.

Corporate

Corporate recorded net expenses in the first quarter of 2006 of $65 million, compared to net expenses of $45 million during the first quarter of 2005. After-tax unrealized foreign exchange losses on U.S. dollar denominated long-term debt were $1 million in the first quarter of 2006 compared to a $5 million loss in the first quarter of 2005.

Net expenses were higher due to increased stock-based compensation expense primarily attributable to higher share prices and adjustments to reflect current measurement of performance criteria, as well as higher depreciation, depletion and amortization expense related to the implementation of our new enterprise resource planning (ERP) system beginning January 2006. These increases were offset by insurance premium revenue earned by our newly formed self-insurance company. The self-insurance revenue is fully offset in the Oil Sands segment, and does not impact consolidated results.

Cash flow used in operations in the first quarter of 2006 was $46 million, compared to $77 million used in the first quarter of 2005. The decrease was primarily due to the earnings factors described above, excluding the impact of the unrealized foreign exchange gains on the U.S. dollar denominated debt and non-cash stock-based compensation expenses.

In April 2006, the Alberta Government substantively enacted a 1.5% reduction in the Alberta corporate income tax rate. We anticipate this will result in a reduction of approximately $125 million in non cash income tax expense on the revaluation of opening future income tax liabilities. The adjustment will be recorded in the second quarter of 2006.

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 $254 million at the end of the first quarter of 2006, compared to a deficiency of $207 million at the end of the first quarter of 2005. The increase is due primarily to increased accounts receivable balances resulting from the accrual of the final settlement for BI insurance, and the reduction in sales of accounts receivable sold under our securitization program. As at March 31, 2006, there were no accounts receivable sold under the securitization program ($340 million at December 31, 2005), although the program remains available.

During the first quarter of 2006, net debt decreased to approximately $2.8 billion from $2.9 billion at December 31, 2005. Cash flow from operations in the amount of $1.3 billion was almost entirely utilized by spending on capital investment, changes in working capital and the reduction in sales of our accounts receivable securitization program. At March 31, 2006 our undrawn lines of credit were approximately $1.3 billion in addition to $340 million available accounts receivable securitization. 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.

In April 2006, the provider of our US$200 million business interruption insurance policy announced that they will be discontinuing all of their insurance programs effective May 15, 2006. We are currently evaluating options to replace this coverage.

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 in 2006	Total spent to date	Status (1)
Oil Sands				
Coker unit (2)	$2,100	$145	$1 075	Project is on schedule and on budget.
Firebag cogeneration and expansion	$400	$45	$165	Project is on schedule and on budget.
EM&R				
Diesel desulphurization and oil sands integration	$800	$90	$565	Schedule revised and on budget. (3)
R&M				
Diesel desulphurization and oil sands integration	$540 (US$445)	$90 (US$75)	$505 (US$415)	Project is on schedule and cost estimate has been revised from the November 2005 estimate of $465 (US$390). (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 9 for discussion.

(4) See page 10 for discussion.

Derivative Financial Instruments

We have continued to enter into crude oil costless collar hedges during the first quarter of 2006. As at March 31, 2006, crude oil hedges totalling 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 will consider additional costless collars of up to 30% of our total crude oil production if strategic opportunities are available.

We had no crude oil hedging loss in the first quarter of 2006 compared to an after tax loss of $65 million in the first 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. Such amounts, which also represent the unrecognized and unrecorded gain (loss), on the contracts, were as follows at March 31:

($ millions)	**2006**	2005
Revenue hedge swaps and collars	**(22)**	(407)
Margin hedge swaps	**—**	(16)
Interest rate and cross-currency interest rate swaps	**13**	28
	(9)	(395)

We also use derivative instruments to hedge risks specific to individual transactions. The estimated fair value of these instruments was $5 million at both March 31, 2006 and December 31, 2005.

Energy Marketing and Trading Activities

For the quarter ended March 31, 2006, we recorded a net pretax loss of $1 million compared to a $2 million gain recorded during the first quarter of 2005, related to the settlement and revaluation of financial energy trading contracts. In the first quarter of 2006, the settlement of physical trading activities also resulted in a net pretax gain of $10 million compared to a $2 million pretax gain in the first quarter of 2005. These gains were included as energy trading and marketing 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 trading and marketing activities resulted in a gain of $5 million for the quarter ended March 31, 2006 compared to net earnings of $2 million in first quarter of 2005. The fair value of unsettled financial energy trading assets and liabilities at March 31, 2006 and December 31, 2005 were as follows:

($ millions)	**2006**	2005
Energy trading assets	**14**	82
Energy trading liabilities	**17**	70
Net energy trading assets	**(3)**	12

Control Environment

Based on their evaluation as of March 31, 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 and Exchange Act of 1934 (the Exchange Act)) are effective to ensure that information required to be disclosed by us in reports that we file or submit 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 March 31, 2006, there were no changes in our internal control over financial reporting that occurred during the three month period ended March 31, 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 controls and procedures and internal control over financial reporting and will make any modifications from time to time as deemed necessary.

During the first quarter ended March 31, 2006 our internal control over financial reporting has undergone significant changes and redesign as several business units implemented our new ERP system, designed to support our growth plan, on January 1, 2006. The business units affected by this implementation were Oil Sands, EM&R – Canada, and Corporate. 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 compensating controls, verifications and testing to ensure data integrity.

The phased implementation of our ERP system is currently planned for completion 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 first quarter of 2006 was $48 million.

Non-GAAP Financial Measures

Certain financial measures referred to in this MD&A 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. We include cash flow from operations, return on capital employed (ROCE) and Oil Sands cash and total operating costs per barrel 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 March 31, 2006 interim basis, please refer to page 26 of the Quarterly 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 March 31, 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:

For the three months ended March 31		**2006**	2005
Cash flow from operations ($ millions)	A	**1 314**	294
Weighted number of shares outstanding (millions of shares)	B	**458.2**	454.9
Cash flow from operations (per share)	(A / B)	**2.87**	0.65

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 total operations and Firebag in-situ reconcile to the schedules of segmented data when combined.

OIL SANDS OPERATING COSTS – TOTAL OPERATIONS

		Quarter ended March 31			
		2006		2005	
		$ millions	$/barrel	$ millions	$/barrel
Operating, selling and general expenses		**508**		321	
Less: natural gas costs and inventory changes		**(107)**		(75)	
Less: non-monetary transactions		**(48)**		—	
Accretion of asset retirement obligations		**7**		6	
Taxes other than income taxes		**10**		7	
Cash costs		**370**	**15.55**	259	20.55
Natural gas		**82**	**3.45**	68	5.40
Imported bitumen (net of other reported product purchases)		**1**	**0.05**	1	0.10
Total cash operating costs	A	**453**	**19.05**	328	26.05
In-situ (Firebag) start-up costs	B	**21**	**0.90**	—	—
Total cash operating costs after start-up costs	A+B	**474**	**19.95**	328	26.05
Depreciation, depletion and amortization		**93**	**3.90**	79	6.25
Total operating costs		**567**	**23.85**	407	32.30
Production (thousands of barrels per day)		**264.4**		139.9	

OIL SANDS OPERATING COSTS – FIREBAG IN-SITU BITUMEN PRODUCTION

	Quarter ended March 31			
	2006		2005	
	$ millions	$/barrel	$ millions	$/barrel
Operating, selling and general expenses	**53**		32	
Less: natural gas costs and inventory changes	**(19)**		(17)	
Taxes other than income taxes	**1**		—	
Cash costs	**35**	**14.20**	15	8.90
Natural gas	**19**	**7.70**	17	10.10
Cash operating costs	**54**	**21.90**	32	19.00
Depreciation, depletion and amortization	**17**	**6.90**	8	4.75
Total operating costs	**71**	**28.80**	40	23.75
Production (thousands of barrels per day)	**27.4**		18.7	

LEGAL NOTICE – FORWARD-LOOKING INFORMATION

This management's discussion and analysis contains certain forward-looking statements that are based on our current expectations, estimates, projections and assumptions that were made by in light of our experience and its perception of historical trends.

All statements that address expectations or projections about the future, including statements about our 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," "intends," "believes," "projects," "could," "goal," "target," "stage is set," "outlook," "continue," 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; 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, royalty and tax and its success at exploration and development drilling and related activities; the maintenance of satisfactory relationships with unions, employee associations and joint venture partners; competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternative sources of energy; uncertainties resulting from potential delays or changes in plans with respect to projects or capital expenditures; actions by governmental authorities including the imposition of taxes or changes to fees and royalties, changes in environmental, royalty and tax 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)	Three months ended March 31 2006	2005 (restated) (note 2)
Revenues (note 10)	**3 858**	2 074
Expenses		
Purchases of crude oil and products	**951**	816
Operating, selling and general (notes 2 and 6)	**772**	543
Energy marketing and trading activities (note 3)	**262**	147
Transportation and other costs	**51**	34
Depreciation, depletion and amortization (note 2)	**158**	137
Accretion of asset retirement obligations	**8**	8
Exploration	**31**	17
Royalties (note 9)	**329**	115
Taxes other than income taxes	**140**	120
Gain on disposal of assets	**(4)**	—
Project start-up costs	**21**	3
Financing expenses (note 4)	**7**	7
	2 726	1 947
Earnings Before Income Taxes	**1 132**	127
Provision for Income Taxes (note 2)		
Current	**(1)**	29
Future	**420**	31
	419	60
Net Earnings	**713**	67
Per Common Share (dollars), (note 5)		
Basic	**1.56**	0.15
Diluted	**1.52**	0.14
Cash dividends	**0.06**	0.06

See accompanying notes.

CONSOLIDATED BALANCE SHEETS

(unaudited)

($ millions)	March 31 2006	December 31 2005 (restated) (note 2)
Assets		
Current assets		
Cash and cash equivalents	**117**	165
Accounts receivable	**1 556**	1 139
Inventories	**447**	523
Income taxes receivable	**18**	6
Future income taxes	**83**	83
Total current assets	**2 221**	1 916
Property, plant and equipment, net	**13 560**	12 966
Deferred charges and other (note 2)	**300**	267
Total assets	**16 081**	15 149
Liabilities and Shareholders' Equity		
Current liabilities		
Short-term debt	**29**	49
Accounts payable and accrued liabilities (note 9)	**1 715**	1 830
Taxes other than income taxes	**52**	56
Total current liabilities	**1 796**	1 935
Long-term debt	**2 914**	3 007
Accrued liabilities and other	**1 027**	1 005
Future income taxes (note 2)	**3 626**	3 206
Shareholders' equity (see below)	**6 718**	5 996
Total liabilities and shareholders' equity	**16 081**	15 149

Shareholders' Equity

	Number (thousands)		Number (thousands)	
Share capital	**458 714**	**759**	457 665	732
Contributed surplus		**56**		50
Cumulative foreign currency translation		**(78)**		(81)
Retained earnings (note 2)		**5 981**		5 295
		6 718		5 996

See accompanying notes.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited)

($ millions)	Three months ended March 31 **2006**	2005 (restated) (note 2)
Operating Activities		
Cash flow from operations	**1 314**	294
Decrease (increase) in operating working capital		
Accounts receivable	**(417)**	(226)
Inventories	**76**	(4)
Accounts payable and accrued liabilities	**(241)**	175
Taxes payable	**(16)**	(23)
Cash flow from operating activities	**716**	216
Cash Used in Investing Activities	**(657)**	(576)
Net Cash Surplus (Deficiency) Before Financing Activities	**59**	(360)
Financing Activities		
Decrease in short-term debt	**(20)**	(22)
Net increase (decrease) in other long-term debt	**(94)**	311
Issuance of common shares under stock option plan	**22**	31
Dividends paid on common shares	**(25)**	(25)
Deferred revenue	**10**	16
Cash provided by (used in) financing activities	**(107)**	311
Increase (Decrease) in Cash and Cash Equivalents	**(48)**	(49)
Cash and Cash Equivalents at Beginning of Period	**165**	88
Cash and Cash Equivalents at End of Period	**117**	39

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	—	—	—	67
Dividends paid on common shares	—	—	—	(25)
Issued for cash under stock option plan	31	—	—	—
Issued under dividend reinvestment plan	2	—	—	(2)
Stock-based compensation expense	—	4	—	—
Foreign currency translation adjustment	—	—	1	—
At March 31, 2005	684	36	(54)	4 286
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)
As at December 31, 2005 as restated	732	50	(81)	5 295
Net earnings	**—**	**—**	**—**	**713**
Dividends paid on common shares	**—**	**—**	**—**	**(25)**
Issued for cash under stock option plan	**25**	**(3)**	**—**	**—**
Issued under dividend reinvestment plan	**2**	**—**	**—**	**(2)**
Stock-based compensation expense	**—**	**9**	**—**	**—**
Foreign currency translation adjustment	**—**	**—**	**3**	**—**
At March 31, 2006	**759**	**56**	**(78)**	**5 981**

See accompanying notes.

SCHEDULES OF SEGMENTED DATA

(unaudited)

Three months ended March 31

($ 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	**1 550**	553	**174**	131	**892**	765	**586**	411	**1**	1	**3 203**	1 861
Energy marketing and trading activities	**—**	—	**—**	—	**274**	150	**—**	—	**(5)**	—	**269**	150
Net insurance proceeds (note 10)	**385**	63	**—**	—	**—**	—	**—**	—	**—**	—	**385**	63
Intersegment revenues	**185**	77	**6**	6	**—**	—	**—**	—	**(191)**	(83)	**—**	—
Interest	**—**	—	**—**	—	**—**	—	**—**	—	**1**	—	**1**	—
	2 120	693	**180**	137	**1 166**	915	**586**	411	**(194)**	(82)	**3 858**	2 074
Expenses												
Purchases of crude oil and products	**3**	9	**—**	—	**646**	561	**495**	329	**(193)**	(83)	**951**	816
Operating, selling and general	**508**	321	**24**	21	**124**	108	**43**	32	**73**	61	**772**	543
Energy marketing and trading activities	**—**	—	**—**	—	**266**	147	**—**	—	**(4)**	—	**262**	147
Transportation and other costs	**37**	24	**6**	5	**1**	1	**7**	4	**—**	—	**51**	34
Depreciation, depletion and amortization	**93**	79	**34**	31	**20**	18	**4**	6	**7**	3	**158**	137
Accretion of asset retirement obligations	**7**	6	**1**	2	**—**	—	**—**	—	**—**	—	**8**	8
Exploration	**22**	10	**9**	7	**—**	—	**—**	—	**—**	—	**31**	17
Royalties (note 9)	**285**	87	**44**	28	**—**	—	**—**	—	**—**	—	**329**	115
Taxes other than income taxes	**21**	7	**—**	—	**79**	83	**40**	30	**—**	—	**140**	120
Gain on disposal of assets	**—**	—	**(4)**	—	**—**	—	**—**	—	**—**	—	**(4)**	—
Project start-up costs	**21**	3	**—**	—	**—**	—	**—**	—	**—**	—	**21**	3
Financing expenses	**—**	—	**—**	—	**—**	—	**—**	—	**7**	7	**7**	7
	997	546	**114**	94	**1 136**	918	**589**	401	**(110)**	(12)	**2 726**	1 947
Earnings (loss) before income taxes	**1 123**	147	**66**	43	**30**	(3)	**(3)**	10	**(84)**	(70)	**1 132**	127
Income taxes	**(403)**	(64)	**(24)**	(17)	**(12)**	—	**1**	(4)	**19**	25	**(419)**	(60)
Net earnings (loss)	**720**	83	**42**	26	**18**	(3)	**(2)**	6	**(65)**	(45)	**713**	67
As at March 31												
TOTAL ASSETS	**12 096**	9 463	**1 367**	1 005	**2 235**	1 460	**1 117**	725	**(734)**	(176)	**16 081**	12 477

SCHEDULES OF SEGMENTED DATA (continued)

(unaudited)

Three months ended March 31

($ millions)	Oil Sands		Natural Gas		Energy Marketing and Refining – Canada		Refining and Marketing – U.S.A.		Corporate and Eliminations		Total	
	2006	2005	**2006**	2005	**2006**	2005	**2006**	2005	**2006**	2005	**2006**	2005
CASH FLOW BEFORE FINANCING ACTIVITIES												
Cash flow from (used in) operating activities:												
Cash flow from (used in) operations												
Net earnings (loss)	**720**	83	**42**	26	**18**	(3)	**(2)**	6	**(65)**	(45)	**713**	67
Exploration expenses	**—**	—	**5**	7	**—**	—	**—**	—	**—**	—	**5**	7
Non-cash items included in earnings												
Depreciation, depletion and amortization	**93**	79	**34**	31	**20**	18	**4**	6	**7**	3	**158**	137
Income taxes	**403**	64	**24**	17	**12**	—	**(1)**	4	**(18)**	(54)	**420**	31
Gain on disposal of assets	**—**	—	**(4)**	—	**—**	—	**—**	—	**—**	—	**(4)**	—
Stock-based compensation expense	**—**	—	**—**	—	**—**	—	**—**	—	**9**	4	**9**	4
Other	**(2)**	25	**(1)**	2	**1**	7	**2**	2	**21**	(12)	**21**	24
Increase (decrease) in deferred credits and other	**(5)**	(3)	**—**	—	**—**	—	**(3)**	—	**—**	27	**(8)**	24
Total cash flow from (used in) operations	**1 209**	248	**100**	83	**51**	22	**—**	18	**(46)**	(77)	**1 314**	294
Decrease (increase) in operating working capital	**(200)**	(36)	**18**	(16)	**(83)**	(61)	**20**	(73)	**(353)**	108	**(598)**	(78)
Total cash flow from (used in) operating activities	**1 009**	212	**118**	67	**(32)**	(39)	**20**	(55)	**(399)**	31	**716**	216
Cash from (used in) investing activities:												
Capital and exploration expenditures	**(407)**	(370)	**(115)**	(82)	**(118)**	(78)	**(108)**	(67)	**(4)**	(12)	**(752)**	(609)
Deferred maintenance shutdown expenditures	**—**	(25)	**—**	—	**—**	—	**(42)**	—	**—**	—	**(42)**	(25)
Deferred outlays and other investments	**—**	(1)	**—**	—	**—**	(1)	**—**	—	**(2)**	—	**(2)**	(2)
Proceeds from disposals	**—**	21	**13**	—	**—**	—	**—**	—	**—**	—	**13**	21
Decrease in investing working capital	**117**	31	**—**	—	**7**	8	**2**	—	**—**	—	**126**	39
Total cash (used in) investing activities	**(290)**	(344)	**(102)**	(82)	**(111)**	(71)	**(148)**	(67)	**(6)**	(12)	**(657)**	(576)
Net cash surplus (deficiency) before financing activities	**719**	(132)	**16**	(15)	**(143)**	(110)	**(128)**	(122)	**(405)**	19	**59**	(360)

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 March 31, 2006 and the results of its operations and cash flows for the three month periods ended March 31, 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 March 31	
($ millions, (decrease))	**2006**	2005
Deferred charges and other	**(231)**	(114)
Total assets	**(231)**	(114)
Future income tax liabilities	**(78)**	(36)
Retained earnings	**(153)**	(78)
Total liabilities and shareholders' equity	**(231)**	(114)

Change in Consolidated Statements of Earnings

	Three months ended March 31	
($ millions, increase/(decrease))	**2006**	2005
Operating, selling and general	**82**	75
Depreciation, depletion and amortization	**(53)**	(28)
Future income taxes	**(10)**	(16)
Net earnings	**(19)**	(31)
Per common share – basic (dollars)	**(0.04)**	(0.07)
Per common share – diluted (dollars)	**(0.04)**	(0.07)

(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 in the first quarter of 2006 was $48 million.

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 March 31, 2006 these activities resulted in a net pretax gain of $10 million (2005 – net pretax gain $2 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 March 31, 2006, a net pretax loss of $1 million (2005 – net pretax gain $2 million) resulted from the settlement and revaluation of the financial contracts. 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)	March 31 **2006**	December 31 2005
Energy trading assets	**14**	82
Energy trading liabilities	**17**	70
Net energy trading assets (liabilities)	**(3)**	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	**(14)**
Fair value of contracts entered into during the period	**2**
Changes in values attributable to market price and other market changes	**(3)**
Fair value of contracts outstanding at March 31, 2006	**(3)**

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

4. FINANCING EXPENSES

($ millions)	Three months ended March 31 **2006**	2005
Interest on debt	**39**	33
Capitalized interest	**(33)**	(26)
Net interest expense	**6**	7
Foreign exchange loss on long-term debt	**1**	6
Other foreign exchange gain	**—**	(6)
Total financing expenses	**7**	7

5. RECONCILIATION OF BASIC AND DILUTED EARNINGS PER COMMON SHARE

($ millions)	Three months ended March 31 2006	2005
Net earnings	**713**	67
(millions of common shares)		
Weighted-average number of common shares	**458**	455
Dilutive securities:		
Options issued under stock-based compensation plans	**12**	8
Weighted-average number of diluted common shares	**470**	463
(dollars per common share)		
Basic earnings per share [a]	**1.56**	0.15
Diluted earnings per share [b]	**1.52**	0.14

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 260,000 options to new employees in the first quarter of 2006 (264,000 options granted during the first quarter of 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, 1,509,000 options were granted in the first quarter of 2006 (1,291,000 options granted during the first quarter of 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:

	Three months ended March 31 2006	2005
Quarterly dividend per share	**$0.06**	$0.06
Risk-free interest rate	**4.08%**	3.77%
Expected life	**6 years**	6 years
Expected volatility	**29%**	28%
Weighted-average fair value per option	**$32.30**	$13.88

Stock-based compensation expense recognized in the first quarter of 2006 related to stock options plans was $9 million (2005 – $4 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)	Three months ended March 31 **2006**	2005
Net earnings – as reported	**713**	67
Less: compensation cost under the fair value method for pre-2003 options	**2**	2
Pro forma net earnings	**711**	65
Basic earnings per share		
As reported	**1.56**	0.15
Pro forma	**1.55**	0.14
Diluted earnings per share		
As reported	**1.52**	0.14
Pro forma	**1.51**	0.14

(b) Performance Share Units (PSUs)

In the first quarter of 2006 the company issued 390,000 (2005 – 436,000) PSUs. Expense recognized in the first quarter of 2006 was $24 million (2005 – $3 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 three months ended March 31.

	Pension Benefits		Other Post-retirement Benefits	
	2006	2005	**2006**	2005
Current service costs	**11**	8	**1**	2
Interest costs	**10**	10	**2**	2
Expected return on plan assets	**(8)**	(7)	**—**	—
Amortization of net actuarial loss	**7**	5	**—**	—
Net periodic benefit cost	**20**	16	**3**	4

8. SUPPLEMENTAL INFORMATION

($ millions)	Three months ended March 31 **2006**	2005
Interest paid	**53**	46
Income taxes paid	**11**	34

Revenue Hedges

Strategic Crude Oil at March 31, 2006

	Quantity (bpd)	Average Price (US$/bbl) (a)	Revenue Hedged (Cdn$ millions) (b)	Hedge Period (c)
Costless collars	50 000	50.00 – 91.70	802 – 1 472	2006
Costless collars	50 000	50.00 – 91.70	1 065 – 1 953	2007

Natural Gas at March 31, 2006

	Quantity (GJ/day)	Average Price (Cdn$/GJ)	Revenue Hedged (Cdn$ millions)	Hedge Period (c)
Swaps	4 000	6.58	7	2006
Costless collars	10 000	8.75 – 13.38	19 – 29	2006 (d)
Swaps	4 000	6.11	9	2007

Margin Hedges at March 31, 2006

	Quantity (bpd)	Average Margin (US$/bbl)	Margin Hedged (Cdn$ millions) [b]	Hedge Period [c]
Refined product sale and crude purchase swaps	2 508	11.23	2	2006 [e]

Foreign Currency Hedges at March 31, 2006

	Notional (Euro millions)	Average Forward Rate	Dollars Hedged (Cdn$ millions)	Hedge Period
Euro/Cdn forward	9.9	1.42	14	2006 [f]
Euro/Cdn forwards	20.6	1.40	29	2007 [g]

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

(b) The revenue and margin hedged is translated to Cdn$ at the March 31, 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 April to October 2006, inclusive.

(e) For the period April to May 2006, inclusive.

(f) Settlement for applicable forward in April 2006.

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

9. 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 $285 million ($182 million after-tax) for the first three months of 2006 compared to $87 million ($53 million after-tax) for the first three months of 2005. We estimate 2006 annualized Crown Royalties to be approximately $950 million ($608 million after-tax) based on three months of actual results including the final $385 million in business interruption insurance proceeds, together with 2006 forward crude oil pricing of US$69.02 as at March 31, 2006, current forecasts of production, capital and operating costs for the remainder of 2006, a Canadian/US foreign exchange rate of $0.88, 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 $44 million ($28 million after tax).

10. SUBSEQUENT EVENTS

In April 2006, as a result of the agreement of final terms for the settlement of its business interruption claim, the company determined that $385 million (US$330 million) in proceeds were unconditionally received or receivable. The proceeds relate to business activity during 2005 and have accordingly been recognized as revenue in the first quarter.

In April 2006, the Alberta Government substantively enacted a 1.5% reduction in the Alberta corporate income tax rate. The company anticipates that this will result in an approximately $125 million reduction in non cash income tax expense on the revaluation of opening future income tax liabilities. The adjustment will be recorded in the second quarter of 2006.

HIGHLIGHTS

(unaudited)

	2006	2005
Cash Flow from Operations		
(dollars per common share – basic)		
For the three months ended March 31		
Cash flow from operations (1)	**2.87**	0.65
Ratios		
For the twelve months ended March 31		
Return on capital employed (%) (2)	**28.5**	15.1
Return on capital employed (%) (3)	**21.0**	12.6
Net debt to cash flow from operations (times) (4)	**0.8**	1.3
Interest coverage on long-term debt (times)		
Net earnings (5)	**18.4**	10.8
Cash flow from operations (6)	**22.5**	14.4
As at March 31		
Debt to debt plus shareholders' equity (%) (7)	**30.46**	34.11
Common Share Information		
As at March 31		
Share price at end of trading		
Toronto Stock Exchange – Cdn$	**89.63**	48.73
New York Stock Exchange – US$	**77.02**	40.21
Common share options outstanding (thousands)	**19 809**	20 307
For the three months ended March 31		
Average number outstanding, weighted monthly (thousands)	**458 230**	454 911

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) For the twelve month period ended; net earnings (2006 – $1,787 million; 2005 – $927 million) adjusted for after-tax financing expenses (2006 – income of $17 million; 2005 – income of $36 million) divided by average capital employed (2006 – $6,279 million; 2005 – $5,902 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 – $8,510 million; 2005 – $7,075 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					Total year
	Mar 31 2006	Dec 31 2005	Sept 30 2005	June 30 2005	Mar 31 2005	Dec 31 2005
OIL SANDS						
Production [1],[a]						
Total operations	**264.4**	267.7	148.2	128.2	139.9	171.3
Firebag	**27.4**	26.0	23.0	8.7	18.7	19.1
Sales [a]						
Light sweet crude oil	**119.2**	108.6	69.9	48.3	75.3	73.3
Diesel	**35.1**	30.7	10.6	9.0	11.8	15.6
Light sour crude oil	**121.0**	104.2	41.7	54.2	38.5	59.8
Bitumen	**—**	7.2	22.3	9.6	18.4	16.6
Total sales	**275.3**	250.7	144.5	121.1	144.0	165.3
Average sales price [2],[b]						
Light sweet crude oil	**69.00**	55.96	52.08	39.20	45.41	49.93
Other (diesel, light sour crude oil and bitumen)	**63.28**	63.84	59.70	50.47	47.31	56.90
Total	**65.75**	60.42	56.01	45.98	46.44	53.81
Total *	**65.75**	66.68	67.95	57.24	54.80	62.68
CASH OPERATING COSTS AND TOTAL OPERATING COSTS – TOTAL OPERATIONS						
Cash costs	**15.55**	16.20	21.65	23.50	20.55	19.60
Natural gas	**3.45**	4.65	6.00	3.60	5.40	4.90
Imported bitumen	**0.05**	0.05	—	—	0.10	0.05
Cash operating costs [3],[c]	**19.05**	20.90	27.65	27.10	26.05	24.55
Firebag start-up costs	**0.90**	0.30	—	—	—	0.10
Total cash operating costs [4],[c]	**19.95**	21.20	27.65	27.10	26.05	24.65
Depreciation, depletion and amortization	**3.90**	3.60	6.10	6.75	6.25	5.30
Total operating costs [5],[c]	**23.85**	24.80	33.75	33.85	32.30	29.95
CASH OPERATING COSTS AND TOTAL OPERATING COSTS – IN-SITU BITUMEN PRODUCTION						
Cash costs	**14.20**	6.70	7.55	21.50	8.90	9.15
Natural gas	**7.70**	13.80	13.25	16.40	10.10	13.05
Cash operating costs [6],[c]	**21.90**	20.50	20.80	37.90	19.00	22.20
Depreciation, depletion and amortization	**6.90**	4.60	4.25	7.60	4.75	4.90
Total operating costs [7],[c]	**28.80**	25.10	25.05	45.50	23.75	27.10
(for the period ended)						
Capital employed [h]	**5 450**	4 472	4 334	4 173	4 164	
(for the twelve months ended)						
Return on capital employed [i]	**35.5**	22.7	15.1	15.7	18.6	
Return on capital employed [i] ****	**26.3**	16.3	11.2	12.2	15.0	

QUARTERLY OPERATING SUMMARY (continued)

(unaudited)

	Mar 31 2006	Dec 31 2005	Sept 30 2005	Jun 30 2005	Mar 31 2005	Total year Dec 31 2005
		For the quarter ended				
NATURAL GAS						
Gross production **						
Natural gas (d)	**196**	193	200	175	191	190
Natural gas liquids (a)	**2.4**	2.3	2.2	2.2	3.0	2.4
Crude oil (a)	**0.8**	0.6	0.7	1.0	0.9	0.8
Total gross production (e)	**35.9**	35.0	36.3	32.4	35.7	34.8
Average sales price (2)						
Natural gas (f)	**9.03**	11.66	8.32	7.29	6.81	8.57
Natural gas (f) *	**8.75**	11.83	8.34	7.26	6.74	8.59
Natural gas liquids (b)	**51.75**	57.85	58.00	52.52	38.32	50.70
Crude oil – Conventional (b)	**60.30**	72.60	63.77	63.86	61.40	64.85
Net wells drilled						
Conventional – Exploratory ***	**5**	3	4	—	5	12
– Development	**4**	13	2	2	5	22
	9	16	6	2	10	34
(for the period ended)						
Capital employed (h)	**590**	563	598	564	490	
(for the twelve months ended)						
Return on capital employed (i)	**31.7**	30.7	22.7	22.5	26.2	
ENERGY MARKETING AND REFINING – CANADA						
Refined product sales (g)						
Transportation fuels						
Gasoline						
Retail	**4.4**	4.5	4.2	4.8	4.6	4.5
Other	**3.6**	3.3	4.2	4.1	4.0	3.9
Jet fuel	**0.7**	0.8	0.9	0.8	0.9	0.9
Diesel	**3.2**	3.4	3.7	3.3	2.7	3.3
Total transportation fuel sales	**11.9**	12.0	13.0	13.0	12.2	12.6
Petrochemicals	**1.2**	0.4	0.7	0.8	0.8	0.7
Heating oils	**0.6**	0.5	0.2	0.3	0.8	0.4
Heavy fuel oils	**0.9**	0.9	0.8	1.4	1.0	1.0
Other	**0.7**	0.5	0.9	0.6	0.3	0.5
Total refined product sales	**15.3**	14.3	15.6	16.1	15.1	15.2
Crude oil supply and refining						
Processed at Sarnia refinery (g)	**9.6**	10.6	10.7	11.1	10.1	10.6
Utilization of refining capacity (i)	**86**	95	96	100	91	95
(for the period ended)						
Capital employed (h)	**535**	486	547	507	525	
(for the twelve months ended)						
Return on capital employed (i)	**11.5**	8.1	7.7	10.1	8.4	
Return on capital employed (i) ****	**6.8**	5.2	5.6	8.1	7.3	

QUARTERLY OPERATING SUMMARY (continued)

(unaudited)

	For the quarter ended					Total year
	Mar 31 2006	Dec 31 2005	Sept 30 2005	Jun 30 2005	Mar 31 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
Other	**5.3**	7.1	8.9	5.0	3.8	6.2
Jet fuel	**0.8**	0.9	0.8	0.7	0.7	0.8
Diesel	**3.2**	3.6	3.9	3.1	2.6	3.3
Total transportation fuel sales	**10.0**	12.3	14.3	9.5	7.8	11.0
Asphalt	**1.0**	1.2	1.8	1.9	1.6	1.6
Other	**0.3**	1.0	1.2	1.2	0.7	1.1
Total refined product sales	**11.3**	14.5	17.3	12.6	10.1	13.7
Crude oil supply and refining						
Processed at Denver refinery (g)	**9.2**	13.0	14.9	11.4	9.2	12.1
Utilization of refining capacity (i)	**65**	91	104	102	96	98
(for the period ended)						
Capital employed (h)	**341**	327	354	349	262	
(for the twelve months ended)						
Return on capital employed (i)	**42.2**	49.4	32.2	17.6	14.5	
Return on capital employed (i) ****	**22.7**	28.9	21.6	13.8	12.2	

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