SUNCOR ENERGY INC. **2008** ANNUAL REPORT

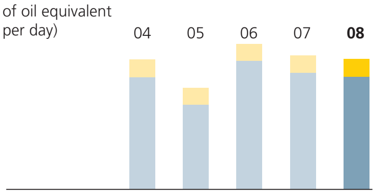
SUNCOR ENERGY

SUNCOR ENERGY is an integrated energy company strategically focused on developing one of the world's largest petroleum resource basins – Canada's Athabasca oil sands. With operations in Canada and the United States, Suncor has become a major North American energy producer and marketer with plans to produce 300,000 barrels per day (+5%/-10%) in 2009. Two years ago, Suncor achieved a major milestone, celebrating the 40th anniversary of our launch of the commercial oil sands industry.

This annual report contains forward-looking statements, including statements about future plans for production growth, that are based on our assumptions and that involve risks and uncertainties. Actual results may differ materially. See page 42 for additional information. All financial information is reported in accordance with Canadian generally accepted accounting principles (GAAP) and in Canadian dollars unless noted otherwise. Financial measures not prescribed by GAAP include cash flow from operations, return on capital employed and cash operating costs. See page 40 for more details. Natural gas converts to crude oil equivalent at a ratio of six thousand cubic feet to one barrel. Barrels of oil equivalent (boe) may be misleading, particularly if used in isolation. This conversion 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 "Suncor", "we", "us", "our" or "the company" mean Suncor Energy Inc., its subsidiaries, partnerships and joint venture investments, unless the context otherwise requires. Suncor has provided cost estimates for projects that, in some cases, are still in the early stages of development. These costs are preliminary estimates only. The actual amount is expected to differ and the difference could be material.

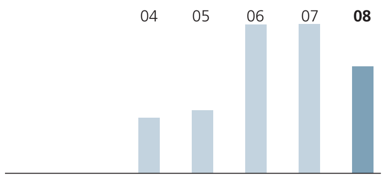
FINANCIAL HIGHLIGHTS

Production
(thousands of barrels of oil equivalent per day)



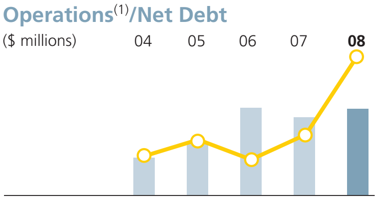
	04	05	06	07	08
Natural Gas	36.8	34.8	34.8	35.8	**36.7**
Oil Sands	226.5	171.3	260.0	235.6	**228.0**
Total	263.3	206.1	294.8	271.4	**264.7**

Net Earnings
($ millions)



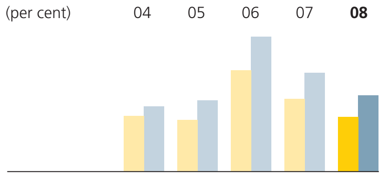
04	05	06	07	08
1 104	1 254	2 969	2 983	**2 137**

Cash Flow from Operations[1]/Net Debt
($ millions)



	04	05	06	07	08
Cash flow from operations	2 055	2 627	4 524	4 009	**4 463**
Net debt	2 109	2 868	1 849	3 248	**7 226**

Return on Capital Employed[1]
(per cent)



	04	05	06	07	08
ROCE[2]	16.4	15.4	30.1	21.5	**16.3**
ROCE[3]	19.4	21.2	40.0	29.3	**22.5**

Other Key Indicators

Year ended December 31 ($ millions)	**2008**	2007	2006	2005	2004
Financial					
Revenues	**30 089**	18 565	16 546	11 781	9 027
Capital and exploration expenditures	**7 590**	5 415	3 613	3 153	1 847
Total assets	**32 528**	24 509	18 959	15 335	11 807
Dollars per common share					
Net earnings attributable to common shareholders – basic	**2.29**	3.23	3.23	1.37	1.22
Net earnings attributable to common shareholders – diluted	**2.26**	3.17	3.16	1.35	1.20
Cash flow from operations	**4.79**	4.35	4.93	2.88	2.27
Cash dividends	**0.20**	0.19	0.15	0.12	0.115
Market price of common stock at December 31 (closing)					
Toronto Stock Exchange (Cdn$)	**23.72**	53.96	45.90	36.66	21.20
New York Stock Exchange (US$)	**19.50**	54.37	39.46	31.57	17.70
Key ratios					
Total debt to total debt plus shareholders' equity (%)	**35.2**	24.3	20.7	33.1	30.9
Net debt to cash flow from operations (times)	**1.6**	0.8	0.4	1.1	1.0
Return on shareholders' equity (%)	**16.2**	28.4	39.0	22.7	25.1

(1) Non-GAAP measures. See page 40.

(2) Includes capitalized costs related to major projects in progress.

(3) Excludes capitalized costs related to major projects in progress.

MESSAGE TO SHAREHOLDERS

As the history books are written, there's little doubt that 2008 will go down as a remarkable year – and not for the reasons many of us might wish. The global credit crisis and resulting market turmoil that characterized the latter part of 2008 has few precedents. Every industry, company, government and individual citizen was somehow impacted by this unexpected economic storm. And it has left all of us trying to steer a course through largely uncharted waters towards something resembling a safe harbour.

Suncor Energy was no exception. Against the backdrop of crude oil prices then edging over $100 per barrel – and soon to jump by a further 50 per cent – Suncor's Board of Directors approved $20.6 billion in capital spending for the final, four-year phase of our longstanding growth strategy aimed at boosting crude oil production to 550,000 barrels per day (bpd) in 2012.

By year's end, the global financial crisis – reflected in continuing tight debt markets and significantly diminished world oil prices – compelled us to reconsider our options.

We could have tried to tough out the storm, keeping most of our expansion plans on track and hoping for the best. But without any clear signals of when the market might begin to recover, we knew this was untenable. To protect the long-term value of our assets, and the best interests of our shareholders, we needed to act swiftly and decisively.

In October, we reduced our 2009 capital spending plans to approximately $6 billion. But with no market correction in sight and to ensure we are living within our means, we visited this again in early 2009, reducing capital spending further to $3 billion. We suspended construction of the Voyageur upgrader and Stages 3 through 6 of our Firebag in-situ bitumen project. Approximately one-third of the 2009 budget has been targeted to growth projects, most of that going towards the orderly wind-down of construction work on the Voyageur upgrader and Firebag Stage 3. The remaining $2 billion has been directed to spending on base business operations.

As you can imagine, these were tough decisions to make. But difficult times demand we do what's right.

I believe our actions will ensure Suncor continues to be an industry leader in responsibly developing Canada's oil sands. We remain committed to a strategy of boosting our production capacity to 550,000 barrels per day – only the timetable has changed. And we are steadfast in the conviction that our core resource has a critical role to play in providing future energy security and economic growth.

Opportunity in Adversity

There's another point that needs stressing. While we would not have wished this economic turmoil on anyone, the fact is we are now faced not just with significant challenges, but with significant opportunities.

In recent years, the oil sands industry has operated in an overheated environment. We've had to deal with sharply inflated materials costs, a tight labour market and limited housing supply. We can now expect each of these challenges to ease. And you can be assured our management team is working closely with our suppliers and contractors to ensure a fair environment for us all.

We now have some breathing space and the opportunity to concentrate on our core business. And we are seizing that opportunity.

Across the company, Suncor is focused on operational excellence and has established a team led by the chief operating officer to identify and realize improvements in every aspect of our business. We intend to make sure all operations meet the highest standards of safety, reliability, environmental responsibility and productivity.

It's impossible to overstate the importance of achieving excellence across our day-to-day operations. This creates the value on which we build the future. For our investors – and for all stakeholders – how we perform today determines their level of confidence in how we will perform tomorrow.

We always knew this was important – now, it's critical. We believe the efficiencies we build into our operations will help us weather the current market storm and give us a clear competitive advantage when the time comes to resume major growth projects.

One reality of the energy industry is that there are factors beyond our control – including the day-to-day price of a barrel of oil. What we *can* control, though, is the way we conduct our business. And for Suncor's employees – one of the most experienced and talented teams in the industry – there's something terrifically empowering about that.

Obviously, the task we face requires some sacrifices. Even so, I've been impressed by the level of commitment and resolve our employees have shown in meeting this latest challenge. Impressed – but not surprised. After all, Suncor has a proud history of turning adversity into advantage. That's how we pioneered the development of Canada's oil sands reserves at a time when many thought they could never be developed on an economic basis. And it's how we led the way on the second phase of oil sands investment with our Millennium expansion in the late nineties – at a time when oil prices were testing their lowest levels in decades. We prevailed because we believed then, as we do now, in the long-term value of our core resource.

Despite recent setbacks, forecasts suggest that, over the medium-to-long-term, world energy demands will increase. As conventional sources of crude oil continue to decline, the oil sands represent a reliable and secure source of new energy that will be needed more than ever to fuel our economy.

Like our response to the recent downward swing in the market, we are ready to respond to a market improvement.

The Path Forward

So what does the path forward look like? And how soon might we expect to resume our growth plans?

In the immediate term, 2009 is poised to be a very solid year for Suncor's base operations. There are none of the scheduled major turnarounds that interrupted production over the past two years and we are working hard to avoid the unexpected shutdowns that hampered our performance in 2008.

Suncor is targeting average production levels of 300,000 bpd (+5%/ – 10%) through the year – a significant improvement over 2008. And we anticipate little difficulty in finding a market for all the oil we produce.

We also expect our natural gas and downstream operations to build on their strong performance in 2008 and to continue providing us with the built-in advantages of integration that have helped our company weather commodity price fluctuations over the years.

As for when we resume our major growth projects, that will depend on many factors. We intend to assess each stage of proposed growth on its own merits, and proceed only when the economics are right.

But it's important to note that as the market recovers, we believe we'll be in a stronger position than most to take advantage. Thanks to Suncor's record of prudent management, we continue to have financial flexibility with conservative debt-to-cash flow ratios and a strong credit profile. And thanks to years of carefully planned growth, we've laid the foundation to give us the ability to quickly resume expansion when the time is right.

The planned third stage of Firebag is a good case in point. Construction of that project is already 50 per cent complete and the economics for moving it forward on a market rebound remain very solid. When that time comes, we won't be putting pen to paper – we'll be putting boots on the ground and should have new production on line approximately 18 months from when we resume construction.

We should never lose sight of the fact that the $20.6 billion Voyageur growth plan was always the sum of many parts. And we have the flexibility to execute segments of that plan when it makes the most sense.

Focusing on a Triple Bottom Line

One of the first things I did after being appointed Suncor's CEO in 1992 was to encourage all of our employees to think about the kind of goals and values our company should embrace as we moved forward.

At the time, both Suncor and the oil sands industry it had pioneered were struggling. We had not yet developed the technology required to make oil sands production cost-effective and competitive. We were further hampered by low, stagnant oil prices.

A lot of corporate restructuring was required and Suncor needed to make substantial investments in new technologies to improve both our economic and environmental performance. We did exactly that – helping to unlock the significant value our shareholders have realized in the ensuing years.

At the same time, I wanted us to agree on a unifying corporate vision – one that we'd write down and refer to as we made future business decisions.

The vision statement we settled on focused on the principle of a triple bottom line – in other words, sustainable development. It stated that "being a sustainable energy company means managing our business in a way that enhances social and economic impacts to society, while striving to minimize the environmental impacts associated with development."

I'm proud to say Suncor has stayed true to that vision through years of impressive growth, developing technologies to help us reduce greenhouse gas emission intensity, lowering our water use through recycling, increasing the rate of land reclamation and lessening our impact on land by developing our in-situ operations. I can assure you we will continue to do so through this period of consolidation and as we reinforce the foundation for the future.

Central to Suncor's vision is that we are in this business for the long haul. Our resource base is massive – an estimated 15 billion barrels of remaining recoverable resources[1]. But our approach to developing these resources has always been measured. We pioneered what has become an industry model for integrated planning in which crude production, upgrading, refining and marketing operations are all connected to a single strategy, with each component complementing the other. This model has served us well in the past – and it will once again help us to navigate through the challenges, and opportunities, our industry now faces.

Now, more than ever, we will benefit from the expertise of Suncor's employees – a team of more than 6,500 professionals who always welcome a challenge. I also remain indebted to Suncor's Board of Directors, who oversee all aspects of governance and are outstanding stewards of shareholders' interests. They excel at challenging management to never settle for "good enough" – and I would like to recognize them for their guidance and support.

Together, I'm confident we will continue to uphold our corporate vision and time-tested strategies for success. We've got the resources, the capital foundation, the people and the plan. I feel privileged to be part of this collective effort and, on behalf of Suncor's employees, management and your Board of Directors, I thank you for your continued support.

Rick George

Rick George
president and chief executive officer

(1) See Remaining Recoverable Resources on page 25.

OUR SCORECARD

Long-term performance

Value at December 31, 2008 of $100 invested in Suncor on March 18, 1992 when the company became publicly traded: $3,142. Value at December 31, 2008 of $100 invested in the S&P 500 on March 18, 1992: $314.(1)

Greenhouse gas intensity at our oil sands business in 2007 compared to 1990: 44% reduction.

Water use in 2007 compared to 2002: 40% absolute reduction.

Target date for reclaiming our first tailings pond to a solid surface: 2010.

2008 — Our goals and what we delivered

Achieve annual oil sands production of 275,000 to 300,000 bpd at a cash operating cost average of $25 to $27 per barrel. Unscheduled maintenance contributed to lower than targeted annual production of 228,000 bpd, and corresponding cash operating costs of $38.50 per barrel.

Target natural gas production of 205 to 215 mmcf equivalent per day. Natural gas production marginally exceeded targets at 220 mmcf equivalent per day.

Advance plans for increased bitumen supply. Regulatory requirements were met to allow ramp-up to begin on Stages 1 and 2 of Firebag in-situ operations. Construction began on Stage 3 and was 50% complete at year-end. However, further work on Stage 3 has been deferred due to market conditions.

Advance plans for increased crude oil production. Suncor completed a $2.3 billion expansion to its existing upgrading operations. Final approval was received for the Voyageur upgrader and construction was 15% complete at year-end before being deferred due to market conditions.

Continue to focus on safety. Suncor continued to advance its process safety management, reorganizing the corporate EHS organization and retaining third-party experts to assess current practice and process improvements.

Focus on efficiency. Major planned maintenance shutdowns, which are expected to improve efficiency and reliability in 2009, were completed at oil sands upgrading and the Sarnia refinery. Company-wide operational strategies aimed at improving production reliability and workforce and material supply processes were advanced.

Maintain a strong balance sheet. At year-end, net debt was $7.2 billion, remaining within a conservative two-times cash flow ratio.

Continue efforts to reduce environmental impact intensity. Significant progress was made on the construction of facilities to reduce sulphur emissions. Expected reduction in water-use intensity at Firebag was not achieved due to higher than planned steaming requirements.

Continue to pursue energy efficiencies, greenhouse gas offsets and new, renewable energy projects. Development work continued on lower emission mining and extraction technologies and accelerated reclamation techniques.

2009 – Our targets and how we'll get there

Achieve annual oil sands production of 300,000 bpd (+5%/–10%) at a cash operating cost average of $33 to $38 per barrel. Increased bitumen supply and reliability improvements in extraction and upgrading are expected to increase production from existing capital assets.

Target production from our natural gas business of 210 mmcf equivalent per day (+5%/–5%). Continue to pursue exploration and development of natural gas assets to offset natural gas purchases for internal consumption at our oil sands operations.

Continue to focus on safety. Continue efforts to identify and reduce potential process safety hazards, and implement enhanced company-wide occupational hygiene and health standards.

Maintain a strong balance sheet. Planned capital spending has been reduced to $3 billion for 2009, with major growth capital investment deferred. Strategic hedging of approximately 60% of target 2009 production provides a degree of insurance to the balance sheet.

Continue efforts to reduce environmental impact intensity. We expect to complete the sulphur recovery plant at Firebag in mid-2009 with start-up and commissioning taking place throughout the remainder of the year. As well, work will continue on developing accelerated reclamation technology. Improved oil sands plant reliability is expected to contribute to lower energy and emissions intensity.

(1) Assuming reinvestment of dividends

This scorecard should be read in conjunction with Suncor's 2008 Management's Discussion and Analysis and audited Consolidated Financial Statements and the accompanying notes.

MANAGEMENT'S DISCUSSION AND ANALYSIS

February 25, 2009

This Management's Discussion and Analysis (MD&A) contains forward-looking information based on Suncor's current expectations, estimates, projections and assumptions. This information is subject to a number of risks and uncertainties, many of which are beyond the company's control. Users of this information are cautioned that actual results may differ materially. For information on material risk factors and assumptions underlying our forward-looking information, see page 42.

This MD&A should be read in conjunction with Suncor's audited Consolidated Financial Statements and the accompanying notes. All financial information is reported in Canadian dollars (Cdn$) and in accordance with Canadian generally accepted accounting principles (GAAP), unless noted otherwise. The financial measures cash flow from operations, return on capital employed (ROCE) and cash and total operating costs per barrel referred to in this MD&A are not prescribed by GAAP and are outlined and reconciled in Non-GAAP Financial Measures on page 40.

Certain prior year amounts 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.

In order to provide shareholders with full disclosure relating to potential future capital expenditures, we have provided cost estimates for projects that, in some cases, are still in the early stages of development. These costs are preliminary estimates only. The actual amounts are expected to differ and these differences may be material. For a further discussion of our significant capital projects, see the Significant Capital Project Update on page 14.

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 regulatory authorities and the United States Securities and Exchange Commission (SEC), including quarterly and annual reports and the Annual Information Form (AIF), filed with the SEC under cover of Form 40-F, is available online at www.sedar.com, www.sec.gov and www.suncor.com. Information contained in or otherwise accessible through our website does not form a part of this MD&A and is not incorporated by reference into this MD&A.

SUNCOR OVERVIEW AND STRATEGIC PRIORITIES

Suncor Energy Inc. is an integrated energy company headquartered in Calgary, Alberta. We operate three businesses:

- **Oil sands**, located near Fort McMurray, Alberta, produces bitumen recovered from oil sands through mining and in-situ technology and upgrades it into refinery feedstock, diesel fuel and byproducts.
- **Natural gas**, located primarily in western Canada, is a conventional exploration and development operation, focused primarily on the production of natural gas. Its natural gas production offsets Suncor's purchases for internal consumption at our oil sands operations.
- **Refining and marketing**, Suncor's downstream operations located in Ontario and Colorado, produce and market the company's refined products to industrial, commercial and retail customers. The refining and marketing business also encompasses third-party energy marketing and trading activities, and provides marketing services for the sale of crude oil, natural gas, refined products and by-products from the oil sands and natural gas segments.

In addition to Suncor's integrated oil sands-focused business activities, the company also invests in renewable energy opportunities. Suncor is a partner in four wind power projects and operates Canada's largest ethanol plant.

Suncor's strategic priorities are:

Operational:

- Focusing on plant and process reliability, efficiency and cost management as part of operational excellence initiatives.
- Developing our oil sands resource base through mining and in-situ technology and supplementing our bitumen production with third-party supply.
- Expanding oil sands mining, in-situ and upgrading facilities to increase crude oil production and improving reliability by providing flexible bitumen feed and upgrading options.
- Integrating oil sands production into the North American energy market through Suncor's refineries and third-party refineries to reduce vulnerability to supply and demand imbalances.
- Advancing environmental and social performance by closely managing impact to air, water and land while also earning continued stakeholder support for our ongoing operations and growth plans.
- Maintaining a strong focus on worker, contractor and community health and safety.

Financial:

- Controlling costs by achieving economies of scale with a strong focus on safe, reliable, cost-effective and environmentally responsible management of our operations.
- Reducing risk associated with commodity price volatility by entering into hedging arrangements to fix prices for crude oil production and by producing natural gas volumes that offset purchases for internal consumption at oil sands operations.
- Ensuring appropriate levels of debt and capital spending are in place to support growth in a fiscally responsible manner.

2008 Overview

- Combined oil sands and natural gas production in 2008 was 264,700 barrels of oil equivalent (boe) per day, compared to 271,400 boe per day in 2007.
- Oil sands cash operating costs averaged $38.50 per barrel during 2008, compared to $27.80 per barrel in 2007.
- Strong commodity prices in the first three quarters of the year led to an average WTI benchmark price almost 40% higher than 2007. However, prices weakened significantly through the last quarter of 2008 and into 2009.
- Commissioning of Suncor's $2.3 billion expansion to one of two oil sands upgraders was completed in the third quarter of 2008. With the completion of this expansion, Suncor has upgrading design capacity of 350,000 bpd.
- Capital spending in 2008 totalled $7.6 billion. Net debt at year-end 2008 was $7.2 billion, compared to $3.2 billion at the end of 2007.
- Suncor achieved a 22.5% return on capital employed (ROCE) excluding capitalized costs related to major projects in progress in 2008, compared to 29.3% in 2007.

SELECTED FINANCIAL INFORMATION

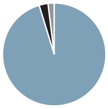
Annual Financial Data

Year ended December 31 ($ millions except per share)	**2008**	2007	2006
Revenues	**30 089**	18 565	16 546
Net earnings	**2 137**	2 983	2 969
Total assets	**32 528**	24 509	18 959
Long-term debt	**7 875**	3 811	2 363
Dividends on common shares	**180**	162	127
Net earnings attributable to common shareholders per share – basic	**2.29**	3.23	3.23
Net earnings attributable to common shareholders per share – diluted	**2.26**	3.17	3.16
Cash dividends per share	**0.20**	0.19	0.15

Outstanding Share Data (1)

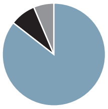
At December 31, 2008 (thousands)	
Number of common shares	935 524
Number of common share options	46 402
Number of common share options – exercisable	24 933

Net Earnings (2)
Year ended December 31
($ millions)



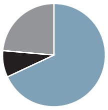
	08	07	06
Oil sands	**2 875**	2 474	2 775
Natural gas	**89**	25	106
Refining and marketing	**51**	444	244

Cash Flow from Operations (2), (3)
Year ended December 31
($ millions)



	08	07	06
Oil sands	**3 838**	3 143	3 903
Natural gas	**368**	248	281
Refining and marketing	**278**	716	451

Ending Capital Employed (2), (3), (4)
At December 31
($ millions)



	08	07	06
Oil sands	**9 352**	6 605	5 039
Natural gas	**1 152**	1 153	857
Refining and marketing	**3 220**	2 489	1 938

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

(2) Excludes Corporate and Eliminations segment.

(3) Non-GAAP measures. See page 40.

(4) Excludes major projects in progress.

CONSOLIDATED FINANCIAL ANALYSIS

This analysis provides an overview of our consolidated financial results for 2008 compared to 2007. For a detailed analysis, see the various business segment discussions.

Net Earnings

Our net earnings were $2.137 billion in 2008, compared with $2.983 billion in 2007 (2006 – $2.969 billion). Excluding unrealized foreign exchange impacts on the company's U.S. dollar denominated long-term debt, income tax rate reductions on opening future income tax liabilities, net insurance proceeds received in 2006 (relating to a January 2005 fire), and project start-up costs, earnings were $3.013 billion in 2008, compared to $2.390 billion in 2007 (2006 – $2.348 billion). The increase in earnings is due primarily to higher annual average price realizations for oil sands and natural gas products. This was partially offset by unscheduled maintenance – which led to higher operating expenses, lower production and increased product purchases – and decreased earnings from our downstream operations due to declining commodity prices in the latter part of the year that reduced the value of inventories.

Although annual average price realizations were stronger in 2008, this was mainly the result of high benchmark commodity prices through the first three quarters of the year. In the fourth quarter of 2008, decreased benchmark commodity prices resulted in price realizations on our oil sands products that were down more than 50% from the second quarter of 2008, and prices have remained low in the first part of 2009.

Net Earnings Components(1)

Year ended December 31 ($ millions, after-tax)	**2008**	2007	2006
Earnings before the following items:	**3 013**	2 390	2 348
Impact of income tax rate reductions on opening future income tax liabilities	**—**	427	419
Oil sands fire accrued insurance proceeds(2)	**—**	—	232
Unrealized foreign exchange gains (loss) on U.S. dollar denominated long-term debt	**(852)**	215	—
Project start-up costs	**(24)**	(49)	(30)
Net earnings as reported	**2 137**	2 983	2 969

(1) This table highlights some of the factors impacting Suncor's after-tax net earnings. For comparability purposes, readers should rely on the reported net earnings that are prepared and presented in the Consolidated Financial Statements and notes in accordance with Canadian GAAP.

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

Industry Indicators

(Average for the year)	**2008**	2007	2006
West Texas Intermediate (WTI) crude oil US$/barrel at Cushing	**99.65**	72.30	66.20
Canadian 0.3% par crude oil Cdn$/barrel at Edmonton	**103.05**	76.65	73.05
Light/heavy crude oil differential US$/barrel WTI at Cushing less Western Canadian Select at Hardisty	**20.10**	22.25	21.45
Natural gas US$/thousand cubic feet (mcf) at Henry Hub	**8.95**	6.90	7.25
Natural gas (Alberta spot) Cdn$/mcf at AECO	**8.15**	6.60	7.00
New York Harbour 3-2-1 crack US$/barrel(1)	**9.10**	13.70	9.80
Exchange rate: US$/Cdn$	**0.94**	0.93	0.88

(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.

Revenues were $30.089 billion in 2008, compared with $18.565 billion in 2007 (2006 – $16.546 billion). The increase was primarily due to the following factors:

- Energy marketing and trading revenues increased to $11.725 billion in 2008, compared to $3.515 billion in 2007. The significant increase was due primarily to the implementation and further development of crude and natural gas trading strategies designed to maximize value from proprietary production and refinery optimization while gaining market expertise and establishing market presence. In addition, higher energy marketing and trading revenues also reflect the stronger average commodity prices in 2008. The results of energy marketing and trading are evaluated net of energy marketing and trading expenses. Pretax earnings from energy marketing and trading activities in 2008 were $102 million (2007 – $49 million). For a discussion of these net results, see page 38.

- Operating revenues benefited from a 38% increase in average U.S. dollar WTI benchmark prices, which increased the selling price of oil sands crude oil production. In addition, stronger price realizations for sales of our oil sands sweet blend and diesel product relative to WTI also increased revenue. High commodity prices also increased revenues from our downstream and natural gas segments. As previously discussed, benchmark prices dropped significantly in the fourth quarter of 2008, negatively impacting operating revenues.

Partially offsetting these increases were the following:

- Oil sands production and sales volumes were lower during 2008, mainly as a result of upgrader reliability and bitumen production issues. In addition, an unplanned shutdown of facilities that supply hydrogen reduced production of higher-value sweet synthetic crude oil and diesel during the third quarter of 2008.
- Our refining and marketing segment experienced lower refined product demand driven by the high prices of finished products, particularly gasoline.

The cost to purchase crude oil and crude oil products was $7.184 billion in 2008, compared to $5.817 billion in 2007 (2006 – $4.670 billion). The increase was primarily due to the following:

- Higher benchmark crude oil prices. This had the largest impact on product purchases for our refining and marketing business, as average WTI prices were more than US$27.00/bbl higher than in 2007.
- Increased purchases of third-party product in our oil sands segment, primarily bitumen purchases to fill additional upgrading capacity, and also product purchases related to increasing the efficiency of cargo shipments made during 2008.

Operating, selling and general expenses were $4.044 billion in 2008 compared with $3.340 billion in 2007 (2006 – $3.066 billion). The primary reasons for the increase were:

- Higher planned and unplanned maintenance expenditures at our oil sands operations. The planned maintenance work was aimed at improving reliability, while the unplanned maintenance related to work on our upgrading and extraction assets.
- Increased energy input costs in our oil sands segment, resulting mainly from strong natural gas prices that saw the average benchmark AECO price in 2008 up almost 25% compared to 2007.

Transportation and other expenses were $275 million in 2008, compared to $182 million in 2007 (2006 – $203 million). The increase in transportation costs was primarily due to a larger number of cargo shipments resulting from increased production of sour crude oil caused by the hydrogen facilities outage in the third quarter of 2008.

Depreciation, depletion and amortization (DD&A) was $1.049 billion in 2008, compared to $864 million in 2007 (2006 – $695 million). The increase primarily reflects the construction and commissioning of the expansion to one of our two oil sands upgraders, in addition to higher DD&A in our natural gas segment resulting from increased production from areas with larger capital bases.

Royalty expenses were $890 million in 2008, compared with $691 million in 2007 (2006 – $1.038 billion). The higher royalties in 2008 were primarily due to increased revenues in our oil sands segment, resulting from high crude prices. This was partially offset by an increase in eligible operating and capital expenditures. In addition, natural gas royalties were higher than the prior year, primarily as a result of the strong natural gas benchmark pricing in 2008. For a discussion of Crown royalties, see page 15.

Taxes other than income taxes were $679 million in 2008, compared to $648 million in 2007 (2006 – $595 million). The increase was primarily due to higher property taxes in our oil sands segment as a result of increased rates and an increased asset base.

Financing expense was $917 million in 2008, compared with income of $211 million in 2007 (2006 – expense of $39 million). The increase in financing expense was primarily due to foreign exchange losses on our U.S. dollar denominated long-term debt. Although interest on our long-term debt increased from the prior year due to additional debt issuance during 2008, we continue to capitalize all of this interest expense. Capitalized interest was $352 million in 2008, compared to $189 million in 2007.

Income tax expense was $995 million in 2008 (32% effective tax rate), compared to $566 million in 2007 (16% effective tax rate) and $828 million in 2006 (22% effective tax rate). The significantly lower effective tax rates in 2007 and 2006 resulted from reductions in tax rates that reduced opening future tax rate liabilities. In addition, there was an increase in the effective tax rate in 2008 as a result of Suncor being unable to realize the full benefit of the capital loss that resulted from the unrealized foreign exchange loss on our U.S. denominated long-term debt.

Corporate Earnings (Expense)

After-tax net corporate expense was $878 million in 2008, compared to earnings of $40 million in 2007 (2006 – $156 million expense). Excluding the impact of group elimination entries, actual after-tax net corporate expense was $869 million in 2008 (2007 – earnings of $43 million; 2006 – $150 million expense).

Breakdown of Net Corporate Earnings (Expense)

Year ended December 31 ($ millions)	**2008**	2007	2006
Corporate earnings (expense)	**(869)**	43	(150)
Group eliminations	**(9)**	(3)	(6)
Total	**(878)**	40	(156)

The net expense in the corporate segment in 2008, compared to net earnings in 2007, was primarily due to unrealized foreign exchange losses on our U.S. denominated long-term debt as a result of the weaker Canadian dollar. As a result of debt issuances during 2008, our U.S. long-term debt balance increased to US$4.15 billion at December 31, 2008 (2007 – US$2.15 billion). After-tax unrealized foreign exchange losses on this U.S. debt were $852 million in 2008, compared to gains of $215 million in 2007 (2006 – nil). Partially offsetting the impact of these foreign exchange losses was a recovery of previously recognized stock-based compensation expense as a result of a decline in our share price.

The corporate net cash deficiency of $659 million was unchanged from 2007 (2006 – $403 million). A $146 million decrease in cash resulting from an increase in working capital was offset by less cash being used in operations and investing activities. The decrease in cash used in operations primarily relates to an operational foreign exchange gain in 2008 compared to a loss in 2007, and the decrease in cash used in investing activities is a result of higher capital spending on the Ripley Wind Power Project in 2007.

Consolidated Cash Flow from Operations

Cash flow from operations was $4.463 billion in 2008, compared to $4.009 billion in 2007 (2006 – $4.524 billion). The increase in cash flow from operations was primarily due to the same factors that impacted earnings.

Dividends

Total dividends paid during 2008 were $0.20 per share, compared with $0.19 per share in 2007 (2006 – $0.15 per share). Suncor's Board of Directors periodically reviews the dividend policy, taking into consideration the company's capital spending profile, financial position, financing requirements, cash flow and other relevant factors.

Quarterly Financial Data

	2008 Three months ended				2007 Three months ended			
($ millions except per share)	**Dec 31**	**Sept 30**	**June 30**	**Mar 31**	Dec 31	Sept 30	June 30	Mar 31
Revenues	**7 196**	**8 946**	**7 959**	**5 988**	5 185	4 802	4 525	4 053
Net earnings (loss)	**(215)**	**815**	**829**	**708**	1 042	627	738	576
Net earnings (loss) attributable to common shareholders per share								
Basic	**(0.24)**	**0.87**	**0.89**	**0.77**	1.12	0.68	0.80	0.63
Diluted	**(0.24)**	**0.86**	**0.87**	**0.75**	1.10	0.66	0.78	0.61

Variations in quarterly net earnings during 2008 and 2007 were due to a number of factors:

- Oil sands production and sales volumes decreased during periods of planned and unplanned maintenance and restricted bitumen supply.
- Changes in benchmark commodity prices throughout 2007 and 2008. WTI averaged US$99.65 per barrel (bbl) in 2008, compared to US$72.30/bbl in 2007.
- Cash operating costs varied due to changes in oil sands production levels, the timing and amount of maintenance activities, and the price and volume of natural gas used for energy in oil sands operations.
- Exchange rate fluctuations impacted the realized commodity prices on our products sold in U.S. dollars, affecting the Canadian dollar revenues earned. Changes in the exchange rate also led to unrealized gains/losses on our U.S. dollar denominated long-term debt.
- Reductions in federal corporate tax rates during the second and fourth quarters of 2007 increased net earnings in those quarters by $67 million and $360 million, respectively.

- Oil sands Crown royalties varied as a result of changes in crude oil commodity prices and the extent and timing of eligible capital and operating expenditures.
- Refined product prices fluctuated as a result of global and regional supply and demand, as well as seasonal demand variations.

For further analysis of quarterly results, refer to Suncor's quarterly reports to shareholders available on our website.

LIQUIDITY AND CAPITAL RESOURCES

The current economic environment has impacted Suncor through both reduced price realizations and higher interest rates on future borrowings. As a result of the current market uncertainty, on January 20, 2009, we announced a reduction to our 2009 planned capital spending.

Our capital resources consist primarily of cash flow from operations and available lines of credit. We believe we will have the capital resources to fund our 2009 capital spending program of $3 billion and to meet current working capital requirements through cash flow from operations and our credit facilities, assuming production of 300,000 bpd and a WTI price of US$40/bbl. Our cash flow from operations depends on a number of factors, including commodity prices, production/sales levels, downstream margins, operating expenses, taxes, royalties, and US$/Cdn$ exchange rates.

To provide an additional element of security to our cash flow from operations, we have entered into crude oil hedges for approximately 125,000 barrels per day (bpd) of production from February 1 through December 31, 2009. These volumes are in addition to previously reported options to sell 55,000 bpd at an equivalent WTI floor price of US$60.00 per barrel from January 1 to December 31, 2009. The combination of the previous options and new fixed-price hedges provide Suncor with an equivalent WTI floor price of about US$53.50 for approximately 180,000 bpd of production in 2009.

For the full year 2010, we have entered into crude oil hedges for approximately 50,000 bpd at an equivalent WTI floor price of US$50.00 per barrel and a ceiling price of approximately US$68.00 per barrel. This program replaces previously reported 2010 options to sell 55,000 bpd at an equivalent WTI floor price of US$60.00, which was effectively exited by selling similar contracts for gross proceeds of approximately $250 million before tax.

In addition, we are closely managing our operational spending, including a freeze on discretionary salary increases as well as implementing a variety of cost-cutting measures throughout the company.

If additional capital is required, we believe adequate additional financing will be available at commercial terms and rates (which are currently higher than in 2008). Our spending is subject to change due to factors such as internal and regulatory approvals and capital availability. Refer to the discussion under Risk Factors Affecting Performance on page 19 for additional factors that may have an impact on our ability to fund our capital requirements.

In May 2008, the company implemented a two-for-one stock split of its issued and outstanding common shares. Information related to common shares, stock-based compensation, and earnings per share has been restated to reflect the impact of the stock split.

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

Financing Activities

Management of debt levels continues to be a priority given our growth plans. We believe a phased and flexible approach to existing and future growth projects should assist us in maintaining our ability to manage project costs and debt levels.

At December 31, 2008, our net debt (short and long-term debt less cash and cash equivalents) was $7.226 billion, compared to $3.248 billion at December 31, 2007. The increase in debt levels was primarily a result of increased capital spending to fund our growth strategies.

During 2008, the company's $2 billion committed syndicated credit facility was increased to $3.75 billion and its term was extended to 2013, while the company's $330 million committed bilateral credit facility was increased to $480 million and its term extended to 2009. Undrawn lines of credit at December 31, 2008 were approximately $3.0 billion.

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

In June 2008, the company issued 6.10% Notes with a principal amount of US$1.25 billion and 6.85% Notes with a principal amount of US$750 million under an amended US$3.65 billion debt shelf prospectus. These notes bear interest, which is paid semi-annually, and mature on June 1, 2018, and June 1, 2039, respectively.

The net proceeds were added to our general funds, which are used for our working capital needs, sustaining and growth capital expenditures and to repay outstanding commercial paper borrowings.

Interest expense on debt continues to be influenced by the composition of our debt portfolio, and we are currently benefiting from short-term floating interest rates which remain at low levels compared to historical short-term rates. To manage fixed versus floating rate exposure, we have entered into interest rate swaps with investment grade counterparties. At December 31, 2008, we had $200 million of fixed-rate to variable-rate interest swaps (December 31, 2007 – $200 million).

We are subject to financial and operating covenants related to our public market and bank debt. Failure to meet the terms of one or more of these covenants may constitute an Event of Default as defined in the respective debt agreements, potentially resulting in accelerated repayment of one or more of the debt obligations.

We are currently in compliance with our financial covenant that requires consolidated debt to not be more than 65% of our total capitalization. At December 31, 2008, our consolidated debt to total capitalization was 35% (where consolidated debt is short-term debt plus long-term debt, and total capitalization is consolidated debt plus shareholders' equity). We are also currently in compliance with all operating covenants.

In addition, a very limited number of our commodity purchase agreements, off-balance sheet arrangements (for a discussion of these arrangements see page 15) and derivative financial instrument agreements contain provisions linked to debt ratings that may result in settlement of the outstanding transactions should our debt ratings fall below investment grade status.

All of our debt ratings are currently investment grade. Suncor's current long-term senior debt ratings are BBB+, with a Negative Outlook by Standard & Poor's; A(low), with a Negative Trend by Dominion Bond Rating Service; and Baa1, with a Stable Outlook by Moody's Investors Service.

Aggregate Contractual Obligations

In the normal course of business, the company is obligated to make future payments. These obligations represent contracts and other commitments that are known and non-cancellable.

		Payments Due by Period			
($ millions)	Total	2009	2010-2011 (aggregate)	2012-2013 (aggregate)	Later Years
Fixed-term debt and commercial paper [1]	7 815	934	500	—	6 381
Interest payments on fixed-term debt	8 837	435	858	803	6 741
Capital leases	312	9	19	19	265
Employee future benefits [2]	643	48	105	121	369
Asset retirement obligations [3]	3 471	156	476	302	2 537
Non-cancellable capital spending commitments [4]	470	470	—	—	—
Operating lease agreements, pipeline capacity and energy services commitments [5]	8 108	383	850	873	6 002
Total	29 656	2 435	2 808	2 118	22 295

In addition to the enforceable and legally binding obligations quantified in the above table, we have other obligations for goods and services and raw materials entered into in the normal course of business, which may terminate on short notice. Commodity purchase obligations for which an active, highly liquid market exists, and which are expected to be re-sold shortly after purchase, are one example of excluded items.

(1) Includes $4.150 billion of U.S. and $1.800 billion of Canadian dollar denominated debt that is redeemable at our option. Maturities range from 2011 to 2039. Interest rates vary from 5.39% to 7.15%. We entered into interest rate swap transactions maturing in 2011 that resulted in an average effective interest rate in 2008 of 4.8% on $200 million of our Medium Term Notes. Approximately $934 million of commercial paper with an effective interest rate of 2.2% was issued and outstanding at December 31, 2008.

(2) Represents the undiscounted expected funding by the company to its pension plans as well as benefit payments to retirees for other post-retirement benefits.

(3) Represents the undiscounted amount of legal obligations associated with site restoration on the retirement of assets with determinable lives.

(4) Non-cancellable capital commitments related to capital projects totalled approximately $470 million at the end of 2008. In addition to capital projects, we spend maintenance capital to sustain our current operations. In 2009, we anticipate spending approximately $2 billion towards sustaining capital.

(5) Includes transportation service agreements for pipeline capacity, including tankage for the shipment of crude oil from Fort McMurray to Hardisty, Alberta, as well as energy services agreements to obtain a portion of the power and steam generated by a cogeneration facility owned by a major energy company. Non-cancellable operating leases are for service stations, office space and other property and equipment.

Significant Capital Project Update

In response to current market uncertainty, we announced an update to our Voyageur program schedule on January 20, 2009. A revised capital budget has deferred the company's growth projects. With the new plan, construction on the Voyageur upgrader and Firebag Stage 3 will be wound down and the projects placed in a "safe mode" pending resumption of expansion work. At this time, construction restart and completion targets for these projects, and start up and completion targets for other expansion projects, have not been determined.

Capital growth plans will be reviewed on a quarterly basis in light of market conditions and updates provided as details are known.

Suncor spent $7.6 billion on capital and exploration expenditures in 2008, compared to $5.4 billion in 2007 (2006 – $3.6 billion). A summary of the progress on our significant projects under construction to support both our growth and sustaining needs is provided below. All projects listed below have received Board of Director approval. The estimates and target completion dates do not include project commissioning and start-up.

Project	Plan	Cost Estimate $ millions(1)	Estimate % Accuracy(1)	Spent to Date	Estimated % Complete Engineering	Estimated % Complete Construction	Target Completion Date
Coker unit	Expected to increase production capacity by 90,000 bpd	2 100	+13/–7	2 300	100	100	Complete
Firebag sulphur plant	Supports emission abatement plan at Firebag; capacity to support Stages 1-6	340	+10/–10	270	90	55	Q2 2009
Steepbank extraction plant	Location and new technologies aimed at improving operational performance	850	+10/–10	690	100	70	Q3 2009
Naphtha unit (2)	Increases sweet product mix	650	+10/–10	650	100	60	TBD
North Steepbank expansion of mine (2)	Expected to generate about 180,000 bpd of bitumen	400	+10/–10	125	55	45	TBD
Voyageur program: Firebag (2)	Expansion of Firebag 3-6 is expected to increase bitumen supply	9 000	+18/–13	3 405 (3)			TBD
	– Stage 3				97	50	
	– Stage 4 (4), (5)				70	2	
	– Stage 5 (4), (5)				15	—	
	– Stage 6 (4), (5)				4	—	
Voyageur program: Upgrader 3 (2)	Expected to increase production capacity by 200,000 bpd	11 600	+12/–8	3 545 (3)	80	15	TBD

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

(2) At this time, construction restart and completion targets for these projects is to be determined (TBD). Cost estimates for TBD projects including those currently on hold and in "safe mode" will be subject to revision upon resumption of projects.

(3) Spending to date includes procurement of major project components. For Firebag Stage 3, procurement at year-end 2008 was 95% complete; for Stage 4, 80% complete; for Stage 5, 15% complete; and for Stage 6, 50% complete. For Upgrader 3, procurement was 75% complete.

(4) Pending regulatory approval.

(5) Construction of shared and common services is included in Stage 3 construction.

The preceding paragraphs and table contain forward-looking information and users of this information are cautioned that the actual timing, amount of the final capital expenditures and expected results, including target completion dates, for each of these projects may vary from the plans disclosed in the table. For a list of the material risk factors that could cause actual timing, amount of the final capital expenditures and expected results to differ materially from those contained in the previous table, please see page 19. For additional information on risks, uncertainties and other factors that could cause actual results to differ, please see page 42.

The material factors used to develop target completion dates and cost estimates are: current capital spending plans, the current status of procurement, design and engineering phases of the project; updates from third parties on delivery of services and goods associated with the project; and estimates from major projects teams on completion of future phases of the project. We have assumed that commitments from third parties will be honoured and that material delays and increased costs related to the risk factors referred to above will not be encountered.

Guarantees, Variable Interest Entities and Off-Balance Sheet Arrangements

At December 31, 2008, the company had various indemnification agreements with third parties as described below.

The company had a securitization program in place to sell, on a revolving, fully serviced and limited recourse basis, up to $170 million of accounts receivable (2007 – $170 million) having a maturity of 45 days or less, to a third party. The third party was a multiple party securitization vehicle that provided funding for numerous asset pools. At December 31, 2008, no outstanding accounts receivable had been sold under the program (2007 – nil) and the program has expired. Although the company does not believe it had any significant exposure to credit losses, under the recourse provisions, the company provided indemnification against potential credit losses for certain counterparties. This indemnification did not exceed $57 million in 2008 and no contingent liability or earnings impact was recorded for this indemnification as the company believes it had no significant exposure to credit losses. Proceeds received from new securitizations and proceeds from collections reinvested in securitizations on a revolving basis for the year ended December 31, 2008, were $170 million and approximately $510 million, respectively. The company recorded an after-tax loss of approximately $2 million on the securitization program in 2008 (2007 – $4 million; 2006 – $2 million).

In 1999, the company entered into an equipment sale and leaseback arrangement with a Variable Interest Entity (VIE) for proceeds of $30 million. The VIE's sole asset is the equipment sold to it and leased back by the company. The VIE was consolidated effective January 1, 2005. The initial lease term covered a period of seven years and had been accounted for as an operating lease. The company repurchased the equipment in 2006 for $21 million. As at December 31, 2008 and 2007, the VIE did not have any assets or liabilities.

ROYALTIES

Oil Sands Crown Royalties

Under the Province of Alberta's generic oil sands royalty regime in effect to December 31, 2008 (1997 Generic Regime), Alberta Crown royalties for oil sands projects were payable at the rate of 25% of the difference between a project's annual gross revenues net of related allowable transportation costs (R), less allowable costs (C) including allowable capital expenditures (the R-C Royalty), subject to a minimum royalty at 1% of R. The Alberta government has classified Suncor's current oil sands operations as two distinct "projects" for royalty purposes.

Royalties on our current Firebag in-situ project were under the 1997 Generic Regime until the end of 2008, and assessed based on bitumen value. In December 2008, the government of Alberta enacted the New Royalty Framework which increased royalty rates from the 1997 Generic Regime to a sliding scale royalty of 25% to 40% of R-C, subject to minimum royalty of 1% to 9% of R, depending on oil price. In both cases, the sliding scale royalty moves with increases in WTI prices from Cdn$55/bbl to the maximum rate at a WTI price of Cdn$120/bbl.

Royalties on our base oil sands mining and associated upgrading operations (the "base operations") are modified by Crown Agreements and are assessed on the R-C royalty subject to a minimum royalty as follows:

- Based on upgraded product values until December 31, 2008 with the rates at 25% of R-C, subject to the 1% minimum royalty of R.
- Commencing January 1, 2009, a bitumen-based royalty applies pursuant to Suncor's exercise of its option to transition to the bitumen-based 1997 Generic Regime. The royalty rates will remain at 25% of R-C, subject to the 1% minimum royalty of R, but will apply to a revised R-C, where R will be based on bitumen value and C would exclude substantially all upgrading costs.
- From January 1, 2010 through December 31, 2015, pursuant to our January 2008 Royalty Amending Agreement with the government of Alberta, the New Royalty Framework rates described above will apply to the bitumen royalty for current production levels, subject to a cap of 30% of R-C, and a minimum royalty of 1% to 1.2% of R. In addition, the Suncor Royalty

Amending Agreement provides Suncor with a level of certainty for various matters, including the bitumen valuation methodology, allowed costs, royalty in-kind and certain taxes.

In 2016 and subsequent years, the royalty rates for all of our oil sands operations (our base operation and our Firebag in-situ project) will be the rates prescribed under the New Royalty Framework, unless it is amended or superseded prior to that time.

Oil Sands Mining and In-Situ Royalties

The following table sets forth our estimates of royalties in the years 2009 through 2013, and certain assumptions on which we have based our estimates.

WTI Price/bbl US$	**40**	**50**	**60**
Natural gas (Alberta spot) Cdn$/mcf at AECO	6.50	7.00	7.50
Light/heavy oil differential of WTI at Cushing less Maya at the U.S. Gulf Coast US$	8.00	9.00	11.00
Differential of Maya at the US Gulf Coast less Western Canadian Select at Hardisty, Alberta US$	7.00	7.00	7.00
US$/Cdn$ exchange rate	0.75	0.80	0.85
Crown Royalty Expense (based on percentage of total oil sands revenue) %			
2009 – Bitumen (mining old rates – 25% and 1% min; in-situ new rates[1])	1	1	1
2010 to 2013 – Bitumen (new rates – with limits for mining only[1])	1	1	1-5

(1) Oil Sands royalty rates – see page 15.

The previous table contains forward-looking information and users of this information are cautioned that actual Crown royalty expense may vary from the ranges disclosed in the table. The royalty ranges disclosed in the table were developed using the following assumptions: current agreements with the government of Alberta, royalty rates and other changes enacted effective January 1, 2009 by the government of Alberta, current forecasts of production, capital and operating costs, and the forward estimates of commodity prices and exchange rates described in the table.

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

(i) The government has enacted new Bitumen Valuation Methodology regulations as part of the implementation of the New Royalty Framework effective January 1, 2009. While the interim bitumen valuation methodology in 2009 has been enacted, the permanent valuation methodology for 2010 has yet to be finalized. For our mining operations, the bitumen valuation methodology is based on our interpretation of the terms of our January 2008 Royalty Amending Agreement. That agreement places certain limitations on the bitumen valuation methodology as recently enacted. If our interpretations of these limitations changes, this could impact the royalties payable to the Crown.

(ii) The government enacted new Allowed Cost regulations as part of the implementation of the New Royalty Framework effective January 1, 2009. Further clarification of some Allowed Cost business rules is still expected. We believe that we are sheltered through 2015 from the impact of many of these changes for our mining operations due to our January 2008 Royalty Amending Agreement and from the cost-related changes for our in-situ operations which are forecast to remain in pre-payout royalty for the near term. However, potential changes and the interpretation of the Allowed Cost regulations could, over time, have a significant impact on our calculation of royalties.

(iii) Changes in crude oil and natural gas pricing, production volumes, foreign exchange rates, and capital and operating costs for each oil sands project; further changes to applicable royalty regimes by the government of Alberta; changes in other legislation and the occurrence of unexpected events all have the potential to have an impact on royalties payable to the Crown.

Alberta Natural Gas Crown Royalties

In 2008, royalty rates on natural gas production in Alberta were capped at 30% for gas discovered in 1974 or later and 35% for gas discovered prior to 1974. These rates were subject to reduction if (i) gas prices dropped below \$3.70/gigajoule (\$3.89/mcf), (ii) a gas well qualified for a deep gas royalty holiday incentive, or (iii) a gas well qualified as a low productivity well. The New Royalty Framework, effective from January 1, 2009, is a sliding scale that is dependent on the production rate, depth of the well, and the market price for natural gas, up to a maximum royalty rate of 50%. The framework provides some royalty relief, under the Natural Gas Deep Drilling Program, for wells drilled beyond 2,500 metres true vertical depth, based on the total depth and whether the well is exploratory or developmental. On November 19, 2008, the government of Alberta announced the Transitional Royalty Program available for wells from 1,000 metres to 3,500 metres in measured depth. Companies can elect to be subject to the Transitional Royalty Program for qualifying wells which would cap the maximum royalty at 30%, however, these wells cannot also receive royalty relief from the Natural Gas Deep Drilling Program. The Transitional Royalty Program is available from 2009 to 2013 inclusive. After January 1, 2014, all wells are subject to the New Royalty Framework.

CASH INCOME TAXES

We estimate we will have cash income taxes of 100% to 300% of our provision for income taxes during 2009. We anticipate this increase in 2009 because a portion of Suncor's calendar 2008 income will be included in the calculation of 2009 cash taxes as a result of a different year-end of a Suncor affiliate, and because we anticipate a decrease in the 2009 provision for income taxes. Thereafter, we anticipate our cash income tax position may fluctuate to a maximum of approximately 100% of our provision for income taxes by 2015. Cash income taxes are sensitive to crude oil and natural gas commodity price volatility and the timing of deductibility of capital expenditures for income tax purposes, among other things. This estimate is based on the following assumptions: current forecasts of production, capital and operating costs and the commodity prices and exchange rates described in the table "Oil Sands Mining and In-Situ Royalties" on page 16, assuming there are no changes to the current income tax regime. Our outlook on cash income tax is a forward looking statement and users of this information are cautioned that actual cash income taxes may vary materially from our outlook.

DERIVATIVE FINANCIAL INSTRUMENTS

On January 1, 2008, Suncor adopted the Canadian Institute of Chartered Accountants (CICA) Handbook sections 3862 "Financial Instruments – Disclosures" and 3863 "Financial Instruments – Presentation", which enhance existing disclosures for financial instruments. These new disclosures have been incorporated in the following discussion and in the notes to our financial statements.

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

We have estimated fair values of derivative financial instruments by assessing available market information and appropriate valuation methodologies based on industry-accepted third-party models; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction.

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

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

Commodity and Treasury Hedging Activities

The company has hedged a portion of its forecasted U.S. dollar denominated sales subject to U.S. dollar West Texas Intermediate (WTI) price risk. In February 2009, we entered into crude oil hedges for approximately 125,000 barrels per day (bpd) of production from February 1 through December 31, 2009. These volumes are in addition to previously reported options to sell 55,000 bpd at an equivalent WTI floor price of US$60.00 per barrel from January 1 to December 31, 2009. The combination of the previous options and new fixed-price hedges provide Suncor with an equivalent WTI floor price of about US$53.50 for approximately 180,000 bpd of production in 2009.

For the full year 2010, we have entered into crude oil hedges for approximately 50,000 bpd at an equivalent WTI floor price of US$50.00 per barrel and a ceiling price of approximately US$68.00 per barrel. This program replaces previously reported 2010 options to sell 55,000 bpd at an equivalent WTI floor price of US$60.00, which was effectively exited by selling similar contracts for gross proceeds to Suncor of approximately $250 million before tax.

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

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

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

We periodically enter into interest rate swap contracts as part of our strategy to manage exposure to interest rates. The interest rate swap contracts involve an exchange of floating rate and fixed rate interest payments between ourselves and investment grade counterparties. The differentials on the exchange of periodic interest payments are recognized as an adjustment to interest expense.

The company also manages variability in market interest rates and foreign exchange rates during periods of debt issuance through the use of interest rate swaps and foreign exchange forward contracts.

Significant commodity contracts outstanding at February 10, 2009 were as follows:

Crude Oil	Quantity (bpd)	Price (US$/bbl)(1)	Revenue Hedged (Cdn$ millions)(2)	Hedge Period
Purchased puts	55 000	60.00	1 319	2009 (3)
Fixed price	126 575	50.73	2 566	2009 (4)
Purchased puts	55 000	60.00	1 485	2010 (3)
Sold puts	54 753	60.00	(1 479)	2010 (3)
Collars-floor	49 384	50.00	1 111	2010 (3)
Collars-cap	49 986	68.10	1 532	2010 (3)

Natural Gas	Quantity (MMBtu/day)	Price (US$/MMBtu)	Consumption Hedged (Cdn$ millions) (2)	Hedge Period
Fixed price	25 000	6.92	10	2009 (5)

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

(2) The revenue hedged is translated to Cdn$ at the January 31, 2009 month-end rate and is subject to change as the US$/Cdn$ exchange rate flucturates during the hedge period.

(3) Original hedge term is for full year.

(4) For the period February to December inclusive.

(5) For the period February to March inclusive.

Significant treasury contracts outstanding at February 10, 2009 were as follows:

Description of Swap Transaction	Principal Swapped ($ millions)	Swap Maturity	2008 Effective Interest Rate
Swap of 6.70% Medium Term Notes to floating rates	200	2011	4.8%

The earnings impact associated with our commodity and treasury hedging activities in 2008 was a pretax gain of $465 million (2007 – pretax loss of $4 million).

A reconciliation of changes in accumulated other comprehensive income (AOCI) attributable to derivative hedging activities for the twelve month periods ending December 31 is as follows:

($ millions)	**2008**	2007
AOCI attributable to derivative hedging activities, beginning of the period, net of income taxes of $4 (2007 – $5)	13	8
Current year net changes arising from cash flow hedges, net of income taxes of $2 (2007 – $1)	(7)	8
Net unrealized hedging losses (gains) at the beginning of the year reclassified to earnings during the period, net of income taxes of $3 (2007 – $2)	7	(3)
AOCI attributable to derivative hedging activities, at December 31, net of income taxes of $5 (2007 – $4)	13	13

Energy Marketing and Trading Activities

In addition to derivative contracts used for hedging activities, Suncor uses physical and financial energy derivatives to earn trading and marketing revenues. These energy contracts are comprised of crude oil, natural gas and refined products derivative contracts. The results of these trading activities are reported as energy marketing and trading revenues and expenses in the Consolidated Statements of Earnings and Comprehensive Income. The net pretax gains associated with our energy marketing and trading activities in 2008 were $102 million (2007 – $49 million).

Fair Value of Derivative Financial Instruments

The fair value of derivative financial instruments is the estimated amount we would receive (pay) to terminate the contracts. Such amounts, which also represent the unrealized gain (loss) on the contracts, were as follows at December 31:

($ millions)	**2008**	2007
Derivative financial instruments accounted for as hedges		
Assets	**24**	20
Liabilities	**(13)**	(11)
Derivative financial instruments not accounted for as hedges		
Assets	**635**	18
Liabilities	**(14)**	(21)
Net derivative financial instruments	**632**	6

Risks Associated with Derivative Financial Instruments

Our strategic crude oil hedging program is subject to periodic management reviews to determine appropriate hedge requirements in light of our tolerance for exposure to market volatility as well as the need for stable cash flow to finance future growth.

We may be exposed to certain losses in the event that the counterparties to derivative financial instruments are unable to meet the terms of the contracts. Our exposure is limited to those counterparties holding derivative contracts with net positive fair values at the reporting date. We minimize this risk by entering into agreements with investment grade counterparties. Risk is also minimized through regular management review of the potential exposure to and credit ratings of such counterparties.

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

For further details on our derivative financial instruments, including additional discussion of exposure to risks and our mitigation activities, see note 7 to the Consolidated Financial Statements on page 63.

RISK FACTORS AFFECTING PERFORMANCE

Our financial and operational performance is potentially affected by a number of factors including, but not limited to, commodity prices and exchange rates, environmental regulations, changes to royalty and income tax legislation, credit market conditions, stakeholder support for activities and growth plans, extreme weather, regional labour issues and other issues discussed within Risk Factors Affecting Performance for each of our business segments. A more detailed discussion of our risk factors is presented in our most recent Annual Information Form (AIF)/Form 40-F, filed with securities regulatory authorities. We are continually working to mitigate the impact of potential risks to our stakeholders. This process includes an entity-wide risk review. This internal review is completed annually to ensure all significant risks are identified and appropriately managed. Certain key risk factors are discussed below:

Commodity Prices and Exchange Rates

Our future financial performance remains closely linked to hydrocarbon commodity prices, which may be influenced by many factors including global and regional supply and demand, seasonality, worldwide political events and weather. These factors can cause a high degree of price volatility. For example, from 2006 to 2008, the monthly average price for benchmark WTI crude oil ranged from a low of US$42.04/bbl to a high of US$134.02/bbl. During the same three-year period, the natural gas AECO benchmark monthly average price ranged from a low of $4.45/mcf to a high of $12.11/mcf.

Crude oil prices are based on U.S. dollar benchmarks that result in our realized prices being influenced by the US$/Cdn$ currency exchange rate, thereby creating an element of uncertainty. Should the Canadian dollar strengthen compared to the U.S. dollar, the resulting negative effect on net earnings would be partially offset by foreign exchange gains on our U.S. dollar denominated debt. The opposite would occur should the Canadian dollar weaken compared to the U.S. dollar. Cash flow from operations is not impacted by the effects of currency fluctuations on our U.S. dollar denominated debt.

We mitigate some of the risk associated with changes in commodity prices through the use of derivative financial instruments (see page 17).

SENSITIVITY ANALYSIS [1]

	2008 Average	Change	Approximate Change in Cash Flow from Operations ($ millions)	After-Tax Earnings ($ millions)
Oil Sands				
Realized crude oil price ($/barrel)[2]	95.96	US$ 1.00	66	48
Sales (bpd)	227 000	1 000	16	11
Natural Gas				
Realized natural gas price ($/mcf)[2]	8.23	0.10	5	4
Sales (mmcf/d)	202	10	18	8
Consolidated				
Exchange rate: US$/Cdn$	0.94	0.01		
Effect on oil sands operations			63	45
Effect on U.S. denominated long-term debt				(55)
Total exchange rate impact			63	(10)

(1) The sensitivity analysis shows the main factors affecting Suncor's annual cash flow from operations and earnings based on actual 2008 operations. The table illustrates the potential financial impact of these factors applied to Suncor's 2008 results. A change in any one factor could compound or offset other factors.

(2) Includes the impact of hedging activities. See page 17.

Environmental Regulation and Risk

Environmental regulation affects nearly all aspects of our operations. These regulatory regimes are laws of general application that apply to us in the same manner as they apply to other companies and enterprises in the energy industry. The regulatory regimes require us to obtain operating licenses and permits in order to operate, and impose certain standards and controls on activities relating to mining, oil and gas exploration, development and production, and the refining, distribution and marketing of petroleum products and petrochemicals. Environmental assessments and regulatory approvals are required before initiating most new projects or undertaking significant changes to existing operations. In addition to these specific, known requirements, we expect future changes to environmental legislation, including anticipated legislation for air emissions (Criteria Air Contaminants (CACs) and Greenhouse Gases (GHGs)), will impose further requirements on companies operating in the energy industry.

Some of the issues that are, or may in future be, subject to environmental regulation include:

- the possible cumulative regional impacts of oil sands development;
- manufacture, import, storage, treatment and disposal of hazardous or industrial waste and substances;
- the need to reduce or stabilize various emissions to air;
- withdrawals, use of, and discharges to, water;
- issues relating to land reclamation, restoration and wildlife habitat protection;
- reformulated gasoline to support lower vehicle emissions;
- U.S. implementation of regulation or policy to limit its purchases of oil to oil produced from conventional sources, or U.S. state or federal calculation and regulation of fuel lifecycle carbon content.

Changes in environmental regulation could have a potentially adverse effect on our financial results from the standpoint of product demand, product reformulation and quality, methods of production and distribution and costs. For example, requirements for cleaner-burning fuels could cause additional costs to be incurred, which may or may not be recoverable in the marketplace. The complexity and breadth of these issues make it extremely difficult to predict their future impact on us. Management anticipates capital expenditures and operating expenses could increase in the future as a result of the implementation of new and increasingly stringent environmental regulations. Compliance with environmental regulation can require significant expenditures and failure to comply with environmental regulation may result in the imposition of fines and penalties, liability for clean-up costs and damages, and the loss of important permits and licenses.

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

In compliance with this new legislation, Suncor filed applications in December 2007 to establish baseline intensities for our oil sands facility. In March 2009, Suncor must file compliance reports that show what actions the company took during the year to offset intensities. Compliance options available to Suncor include internal emission reductions, utilizing offset projects or contributing to a government climate change emission management fund.

For the compliance period of January 1 to December 31, 2008, the compliance costs to Suncor are estimated at between $7 million and $8 million. Final costs will be determined with the company's March 2009 compliance report filing to the province of Alberta.

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

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

There remains uncertainty around the outcome and impacts of climate change and other environmental regulations. We continue to actively work to mitigate our environmental impact, including taking action to reduce greenhouse gas emissions, investing in renewable forms of energy such as wind power and biofuels, accelerating land reclamation, installing new emission abatement equipment and pursuing other opportunities such as carbon capture and sequestration.

Regulatory Requirements at Oil Sands Suncor continues work to decrease emissions at our oil sands operations. At our in-situ operation, high emissions in 2007 resulted in intervention by both Alberta Environment and the Alberta Energy and Utilities Board (now known as the Energy Resources Conservation Board or ERCB). The production cap, which limited production to 42,000 bpd, was lifted in the third quarter of 2008. Suncor's planned $340 million Firebag sulphur plant is expected to play a role in managing sulphur emissions for existing and planned in-situ developments.

Any regulatory requirements placed on us could have a material effect on our business and results of operations.

Tailings Management Another area of risk for Suncor is the reclamation of tailings ponds, which contain water, clay and residual bitumen produced through the extraction process. To reclaim tailings ponds, we are using a process referred to as consolidated tailings (CT) technology. At this time, no ponds have been fully reclaimed using this technology. The success of CT technology and time to reclaim the tailings ponds could increase or decrease our current asset retirement cost estimates. We continue to monitor and assess other possible technologies and/or modifications to the CT process now being used. Regulatory approval of our North Steepbank extension of mine is subject to certain conditions related to the performance of CT technology.

For the Millennium, Steepbank, and North Steepbank expansion of our mine we have posted irrevocable letters of credit equal to approximately $271 million with Alberta Environment, representing security for the maximum reclamation liability in the period January 1 through December 31, 2009. For Suncor's oil sands mining leases 86 and 17, we are required to and have posted annually with Alberta Environment an irrevocable letter of credit equal to $0.03 per bbl of crude oil produced as security for the estimated cost of our reclamation activity. This letter of credit equalled $14 million at December 31, 2008. For more information about our reclamation and environmental remediation obligations, refer to Asset Retirement Obligations in the Critical Accounting Estimates section on page 22.

In February 2009, the ERCB released a directive, Tailings Performance Criteria and Requirements for Oil Sands Mining Schemes. The directive establishes performance criteria for CT operations, a requirement for specific approval and monitoring of CT ponds, a requirement for reporting tailings plans, and changes to the ERCB annual mine plan requirements and approval process to regulate tailings operations. We are currently assessing the impact of the directive.

A new reclamation liability management program is under review by the Province of Alberta. The new program would involve increased reporting of progressive reclamation, an asset/liability-based risk assessment, consideration of reserve life, and posting of security.

Regulatory Approvals Before proceeding with most major projects, we must obtain regulatory approvals. The regulatory approval process involves stakeholder consultation, environmental impact assessments and public hearings, among other factors. Failure to obtain regulatory approvals, or failure to obtain them on a timely basis, could result in delays, abandonment, or restructuring of projects and increased costs, all of which could negatively impact future earnings and cash flow.

CRITICAL ACCOUNTING ESTIMATES

Critical accounting estimates are defined as estimates that are important to the portrayal of our financial position and operations, and require management to make judgments based on underlying assumptions about future events and their effects. These underlying assumptions are based on historical experience and other factors that management believes to be reasonable under the circumstances, and are subject to change as new events occur, as more industry experience is acquired, as additional information is obtained and as our operating environment changes. Critical accounting estimates are reviewed annually by the Audit Committee of the Board of Directors. The following are the critical accounting estimates used in the preparation of our Consolidated Financial Statements.

Asset Retirement Obligations (ARO)

We are required to recognize a liability for the future retirement obligations associated with our property, plant and equipment. An ARO liability is only recognized to the extent there is a legal obligation associated with the retirement of a tangible long-lived asset that we are required to settle as a result of an existing or enacted law, statute, ordinance, written or oral contract, or by legal construction of a contract under the doctrine of promissory estoppel. The ARO is based on estimated costs, taking into account the anticipated method and extent of restoration consistent with legal requirements, technological advances and the possible use of the site. Since these estimates are specific to the sites involved, there are many individual assumptions underlying our total ARO amount. These individual assumptions can be subject to change based on experience.

The ARO is re-measured every year-end, and incremental increases are discounted to present value using a credit-adjusted risk-free discount rate. The ARO accretes over time until we settle the obligation, the effect of which is included in a separate line in the Consolidated Statements of Earnings and Comprehensive Income entitled accretion of asset retirement obligations. The discount rate is adjusted as appropriate, to reflect long-term changes in market rates and outlook.

An ARO is not recognized for assets with an indeterminate useful life because the amount cannot be reasonably estimated. An ARO for these assets will be recorded in the first period in which the lives of the assets are determinable.

In connection with company and third-party reviews of ARO during 2008, we increased our estimated undiscounted total obligation to $3.498 billion from the previous estimate of $2.231 billion. The increase was mainly due to a change in the oil sands estimate to $3.163 billion from $1.941 billion, primarily reflecting the inclusion of costs related to conversion of plant equipment to process consolidated tailings (CT), additional extraction operating costs related to production of CT, and increased inflationary estimates. The majority of the costs in oil sands are projected to occur over a time horizon extending to approximately 2060.

The current economic conditions resulted in our credit-adjusted risk-free discount rate increasing to 9.0% at December 31, 2008, from 6.0% at December 31, 2007. The discounted amount of our ARO liability was $1.600 billion at December 31, 2008, compared to $1.072 billion at December 31, 2007. If our credit-adjusted risk-free discount rate had remained unchanged at 6.0%, our ARO liability at December 31, 2008 would have been approximately $160 million larger. The ARO liability is reported as part of accrued liabilities and other in the Consolidated Balance Sheets.

In 2009, the increase in the ARO estimate will result in additional after-tax expenses of approximately $60 million.

Employee Future Benefits

We provide a range of benefits to our employees and retired employees, including pensions and other post-retirement benefits. The determination of obligations under our benefit plans and related expenses requires the use of actuarial valuation methods and assumptions. Assumptions typically used in determining these amounts include, as applicable, rates of employee turnover, future claim costs, discount rates, future salary and benefit levels, return on plan assets, mortality rates and future medical costs. The fair value of plan assets is determined using market values. Actuarial valuations are subject to management judgment. Management continually reviews these assumptions in light of actual experience and expectations for the future. Changes in assumptions are accounted for on a prospective basis. Employee future benefit costs are reported as part of operating, selling and general expenses in our Consolidated Statements of Earnings and Comprehensive Income. The accrued benefit liability is reported as part of accrued liabilities and other in the Consolidated Balance Sheets.

The assumed rate of return on plan assets considers the current level of expected returns on the fixed income portion of the plan assets portfolio, the historical level of risk premium associated with other asset classes in the portfolio and the expected future returns on each asset class. The discount rate assumption is based on the year-end interest rate on high-quality bonds with maturity terms equivalent to the benefit obligations. The rate of compensation increases is based on management's judgment. The accrued benefit obligation and net periodic benefit cost for both pensions and other post-retirement benefits may differ significantly if different assumptions are used. The impact of a 1% change in the assumptions at which pension benefits and other post-retirement benefit liabilities could be effectively settled is disclosed in note 10 to the Consolidated Financial Statements on page 71.

The current economic conditions resulted in an increase to the discount rate used to calculate the year-end benefit obligation to 6.50% at December 31, 2008, from 5.25% at December 31, 2007. This resulted in a $195 million decrease to the benefit obligation. This was partially offset by a $107 million decrease in the value of the plan assets that resulted from lower returns for the plan investments.

Property, Plant and Equipment

We account for our in-situ and natural gas exploration and production activities using the successful efforts method. This policy was selected over the alternative of the full-cost method because we believe it provides timelier accounting of the success or failure of exploration and production activities.

The application of the successful efforts method of accounting requires management to determine the proper classification of activities designated as developmental or exploratory, which then determines the appropriate accounting treatment of the costs incurred. The results from a drilling program can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and industry experience. Where it is determined that exploratory drilling will not result in commercial production, the drilling costs of the exploratory dry hole are written off and reported as part of exploration expenses in the Consolidated Statements of Earnings and Comprehensive Income. Dry hole expense can fluctuate from year to year due to such factors as the level of exploratory spending, the level of risk sharing with third parties participating in the exploratory drilling and the degree of risk in drilling in particular areas.

Properties that are assumed to be productive may, over a period of time, actually deliver oil and gas in quantities different than originally estimated because of changes in reservoir performance. Such changes may require a test for the potential impairment of capitalized properties based on estimates of future cash flow from the properties. An impairment test may also be required as a result of other economic events. Estimates of future cash flows are subject to significant management judgment concerning oil and gas prices, production quantities and operating costs. Where properties are assessed by management to be fully or partially impaired, the book value of the properties is reduced to fair value and either completely removed (written off) or partially removed (written down) in our records and reported as part of depreciation, depletion and amortization expenses, in the Consolidated Statements of Earnings and Comprehensive Income. Negative revisions in natural gas and in-situ reserves estimates will result in an increase in depletion expenses.

Oil and Gas Reserves

Our oil and gas reserves are evaluated by independent qualified reserves evaluators. The estimation of reserves is an inherently complex process and involves the exercise of professional judgment.

Estimates are based on projected future rates of production, estimated commodity prices, engineering data and the timing of future expenditures, all of which are subject to uncertainty. Changes in reserve estimates can have an impact on reported net earnings through revisions to depreciation, depletion and amortization expense, in addition to determining possible writedowns of property, plant and equipment.

RESERVES ESTIMATES

As a Canadian issuer, we are subject to the reporting requirements of Canadian securities regulatory authorities, including the reporting of our reserves in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* (NI 51-101). Prior to 2008, we presented our disclosures in accordance with U.S. disclosure requirements under an exemption from Canadian securities regulatory authorities which was not renewed following our annual disclosures at December 31, 2007.

As a result, reserves information presented for comparative years has been restated to comply fully with NI 51-101, consistent with the presentation format for December 31, 2008 reserve disclosures.

Our reserves and resources have been evaluated, at December 31, 2008, by independent petroleum consultants, GLJ Petroleum Consultants Ltd. (GLJ), in a report dated February 6, 2009 (GLJ Report). The crude oil, natural gas liquids and natural gas reserves estimates presented in the GLJ Report are based on the definitions and guidelines contained in the Canadian Oil and Gas Evaluation Handbook.

Net reserves represent Suncor's undivided gross (working interest) in total reserves after deducting Crown royalties, freehold and overriding royalty interests. Reserve estimates are based on assumptions about future prices, production levels, operating costs, capital expenditures, and the government of Alberta's enacted New Royalty Framework and our specific oil sands royalty agreements. For a full discussion of our Crown royalties, see page 15.

Assumptions reflect market and regulatory conditions, as required, at December 31, 2008, which could differ significantly from other points in time throughout the year, or future periods. Changes in market and regulatory conditions and assumptions can materially impact the estimation of net reserves.

The company's reserves are located primarily in Alberta and British Columbia, Canada.

All of the reserves disclosures presented below reflect forecast pricing. No supplemental constant pricing disclosures have been made.

Reserves Data (Forecast Prices and Costs)

Summary of Oil and Gas Reserves

	Oil[1]		Natural Gas		Natural Gas Liquids	
As at December 31, 2008	Working Interest MMbbl	Net MMbbl	Working Interest Bcf	Net Bcf	Working Interest MMbbl	Net MMbbl
Proved Producing						
Conventional	2	2	459	352	5	4
SCO – Mining	1,571	1,335	—	—	—	—
SCO – In-Situ	94	91	—	—	—	—
Total Proved Producing	1,667	1,428	459	352	5	4
Proved Developed Non-Producing						
Conventional	—	—	50	38	—	—
SCO – In-Situ	45	43	—	—	—	—
Total Proved Developed Non-Producing	45	43	50	38	—	—
Proved Undeveloped						
Conventional	—	—	30	24	—	—
SCO – In-Situ	766	658	—	—	—	—
Total Proved Undeveloped	766	658	30	24	—	—
Total Proved						
Conventional	2	2	539	414	5	4
SCO – Mining	1,571	1,335	—	—	—	—
SCO – In-Situ	905	792	—	—	—	—
Total Proved	2,478	2,129	539	414	5	4
Total Probable						
Conventional	1	—	216	153	2	1
SCO – Mining	745	626	—	—	—	—
SCO – In-Situ	1,808	1,506	—	—	—	—
Total Probable	2,554	2,132	216	153	2	1
Total Proved Plus Probable						
Conventional	3	2	755	567	7	5
SCO – Mining	2,316	1,961	—	—	—	—
SCO – In-Situ	2,713	2,298	—	—	—	—
Total Proved Plus Probable	5,032	4,261	755	567	7	5

(1) Represents light and medium oil for our conventional reserves, and synthetic crude oil (SCO) for our mining and in-situ reserves.

Pricing Assumptions

The following table outlines the benchmark reference prices, as at December 31, 2008, reflected by GLJ in their independent reserves report.

Forecast Prices Used in Preparing Reserves Estimates

Year	Inflation %	Bank of Canada Average Noon Exchange Rate $US/$Cdn	NYMEX WTI Crude Oil at Cushing Oklahoma $US/bbl	Light, Sweet Crude Oil at Edmonton (40 API, 0.3%S) $Cdn/bbl	NYMEX Natural Gas at Henry Hub $US/mmbtu	Natural Gas at AECO $Cdn/mmbtu
2009	2.0	0.825	57.50	68.61	7.00	7.58
2010	2.0	0.850	68.00	78.94	7.50	7.94
2011	2.0	0.875	74.00	83.54	8.00	8.34
2012	2.0	0.925	85.00	90.92	8.75	8.70
2013	2.0	0.950	92.01	95.91	9.20	8.95
2014	2.0	0.950	93.85	97.84	9.38	9.14
2015	2.0	0.950	95.73	99.82	9.57	9.34
2016	2.0	0.950	97.64	101.83	9.76	9.54
2017	2.0	0.950	99.59	103.89	9.96	9.75
2018	2.0	0.950	101.59	105.99	10.16	9.95
2019+	2.0	0.950	+2%/yr	+2%/yr	+2%/yr	+2%/yr

The company's weighted average historical prices realized for the year ended December 31, 2008 were $95.96/bbl for synthetic crude oil, $8.23/mcf for natural gas, and $70.89/bbl for natural gas liquids.

Remaining Recoverable Resources

Suncor holds a 100% interest in its oil sands leases, all located near Fort McMurray in the Athabasca region of Alberta. Based upon independent evaluations conducted by GLJ effective December 31, 2008, our best estimate of remaining recoverable synthetic crude oil resources are as follows:

As at December 31, 2008 (millions of barrels of SCO)	Mining	In-Situ	Total
Total Proved (1)	1,600	900	2,500
Total Probable (1)	700	1,800	2,500
Total Proved Plus Probable Reserves	2,300	2,700	5,000
Contingent Resources – Best Estimate (2), (3)	3,500	6,500	10,000
Remaining Recoverable Resources (4)	5,800	9,200	15,000

(1) Total proved and total probable reserves as per Summary of Oil and Gas Reserves table.

(2) Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. There is no certainty that it will be commercially viable to produce the contingent resources.

(3) Contingent Resources – Best Estimate is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. The best estimate of potentially recoverable volumes is generally prepared independent of the risks associated with achieving commercial production.

(4) Remaining recoverable resources are the unrisked arithmetic sum of proved and probable reserves and best estimate contingent resources.

Remaining recoverable resources were 15,500 millions of barrels of SCO at December 31, 2007. The decrease in 2008 was primarily due to additional data and modeling for the Audet leases.

The contingent resources are not classified as reserves due to the absence of a commercial development plan that includes a firm intent to develop within a reasonable timeframe, and in some cases due to higher uncertainty as a result of lower core-hole drilling density. Our Voyageur South development area, for which we submitted a regulatory application in 2007, is part of our mining contingent resources. Significant mining contingent resources are also associated with our Audet leases, located north of our Firebag leases and immediately adjacent to leases proposed for mining development by other operators. All of our in-situ leases are associated with our Firebag leases. While we consider the contingent resources to be potentially recoverable under reasonable economic and operating conditions, there is no certainty that it will be commercially viable to produce any portion of them.

CONTROL ENVIRONMENT

Based on their evaluation as of December 31, 2008, our chief executive officer and chief financial officer concluded that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the United States Securities Exchange Act of 1934 (the Exchange Act)) are effective to ensure that information required to be disclosed by us in reports that we file or submit to Canadian and U.S. securities authorities is recorded, processed, summarized and reported within the time periods specified in Canadian and U.S. securities laws. In addition, as of December 31, 2008, there were no changes in our internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) – 15d-15(f)) that occurred during 2008 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. We will continue to periodically evaluate our disclosure controls and procedures and internal control over financial reporting and will make any modifications from time-to-time as deemed necessary.

The company has undertaken a comprehensive review of the effectiveness of its internal control over financial reporting based on the Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). For the year ended December 31, 2008, based on that evaluation, the company's internal controls were found to be operating free of any material weaknesses.

The effectiveness of our internal control over financial reporting as at December 31, 2008 was audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report, which is included in our audited Consolidated Financial Statements for the year ended December 31, 2008.

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

CHANGE IN ACCOUNTING POLICIES

Inventories

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

Change in Consolidated Balance Sheets

($ millions, increase)	**As at December 31 2008**	As at December 31 2007
Inventories	**110**	404
Total assets	**110**	404
Future income taxes	**30**	121
Retained earnings	**80**	283
Total liabilities and shareholders' equity	**110**	404

Change in Consolidated Statements of Earnings (Loss) and Comprehensive Income

	Twelve months ended December 31		
($ millions, increase/(decrease))	**2008**	2007	2006
Purchases of crude oil and products	**270**	(153)	(5)
Operating, selling and general	**24**	(51)	14
Future income taxes	**(91)**	53	(7)
Net earnings (loss)	**(203)**	151	(2)
Per common share – basic (dollars)	**(0.22)**	0.16	—
Per common share – diluted (dollars)	**(0.22)**	0.16	—

Segmented Net Earnings Impact

($ millions, increase/(decrease))	Twelve months ended December 31 **2008**	2007	2006
Net earnings			
Oil sands	**(19)**	40	(8)
Refining and marketing	**(202)**	99	9
Corporate and eliminations	**18**	12	(3)
Total	**(203)**	151	(2)

Capital Disclosures

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

Financial Instruments – Disclosures and Presentation

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

International Financial Reporting Standards

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

The company's IFRS conversion project began in 2008. A formal project plan, governance structure, and a project team, including an external advisor, have been established. The project philosophy is to align with current accounting practices and policies, where possible, to minimize the impact of any changes to the business. Regular reporting is provided to senior management and the Audit Committee of the Board of Directors.

The IFRS conversion project consists of four phases: Diagnostic; Design & Planning/Solution Development; Implementation; and Post Implementation.

To date, the IFRS conversion project team has completed the Diagnostic phase, which involved a high-level review of the major differences between Canadian GAAP and IFRS. This assessment has provided insight on the high risk and complex areas relating to the conversion. These areas include accounting for property, plant and equipment, exploration and evaluation of mineral resources, the effects of changes in foreign currency exchange rates, and alternatives available under IFRS 1 – First Time Adoption of IFRS.

Please see the associated table for certain elements of the transition plan, and an assessment of progress. Note that the project team is working through a detailed project plan and that certain project activities and milestones could change.

Given the progress of the project and outcomes identified, we could change our intentions between the time of communicating these key milestones below and the changeover date. Further, changes in regulation or economic conditions at the date of the changeover or through the project could result in changes to the project activities communicated in the following chart.

Key Activity	Key Milestones	Status
Financial Statement Preparation: – Identify differences in Canadian GAAP/IFRS accounting policies. – Select Suncor's ongoing IFRS policies. – Develop financial statement format. – Quantify effects of change in initial IFRS disclosure and 2010 financial statements.	Senior management and steering committee sign-off for all key IFRS accounting policy choices to occur during 2009. Develop draft financial statement format to occur during 2009.	Completed the IFRS diagnostic during 2008, which involved a high level review of the major differences between Canadian GAAP and IFRS. In-depth analysis of issues and accounting policy choices is currently underway.
Training: Define and introduce appropriate level of IFRS expertise for each of the following: – Financial reporting group and operating accounting staff. – Suncor management. – Audit Committee.	Financial reporting group and operating accounting staff training to occur during 2009 as needed. Additional training will occur throughout the project as needs are reassessed. Suncor management and Audit Committee training scheduled to occur during 2009.	Project team expert resources have been identified to provide insights and training. Training for project team members is occurring throughout the project.
Infrastructure: Confirm that business processes and systems are IFRS compliant, including: – Program upgrades/changes. – Gathering data for disclosures.	Confirm that systems can address 2010 parallel processing requirements by 2009 and identify deficiency areas. Confirmation that business processes and systems are IFRS compliant will occur throughout the project.	Diagnostic analysis regarding current IT systems completed. Currently reviewing options to address business process changes and parallel processing during 2010.
Control Environment: – For all accounting policy changes identified, assess control design and effectiveness implications. – Implement appropriate changes.	All key control and design effectiveness implications are being assessed as part of the key IFRS differences and accounting policy choices through 2009.	Analysis of control issues is underway in conjunction with review of accounting issues and policies.
External Communications: Assess the effects of key IFRS related accounting policy and financial statement changes on external communications. In particular: – Confirm 2011 investor communications are IFRS compliant regarding guidance and expected earnings. – Monitor and update MD&A communications package. – Confirm investor relations process can respond to IFRS-related queries.	Analyze and publish the effect of IFRS on the financial statements throughout the project.	IFRS disclosure in the MD&A will be updated throughout the project. Vice President, Investor Relations is part of the IFRS Conversion Steering Committee.

RECENTLY ISSUED CANADIAN ACCOUNTING STANDARDS

Goodwill and Intangible Assets

In February 2008, the CICA approved Handbook section 3064 "Goodwill and Intangible Assets". Effective January 1, 2009, this new standard replaces section 3062 "Goodwill and Other Intangible Assets" and section 3450 "Research and Development Costs". The standard focuses on the criteria for asset recognition in the financial statements, including those internally developed. The new standard will not materially impact net earnings or financial position, however will result in the reclassification and presentation of certain balances on the balance sheet. At December 31, 2008, $566 million of turnaround costs would have been reclassified as part of property, plant and equipment (December 31, 2007 – $296 million).

OIL SANDS

Located near Fort McMurray, Alberta, our oil sands business forms the foundation of our operations and represents the most significant portion of our assets. The oil sands business recovers bitumen through mining and in-situ development and upgrades it into refinery feedstock, diesel fuel and byproducts. Our marketing plan also allows for sales of bitumen when market conditions are favourable or when operating conditions warrant.

Oil sands strategy focuses on:

- Acquiring long-life leases with substantial bitumen resources in place.
- Sourcing low-cost bitumen supply through mining, in-situ development and third-party supply agreements, and upgrading this bitumen supply into high value crude oil products.
- Increasing production capacity and improving reliability through staged expansion, continued focus on operational excellence and worksite safety.
- Reducing costs through the application of technologies, economies of scale, direct management of growth projects, strategic alliances with key suppliers and continuous improvement of operations.
- Pursuing new technology applications to increase production, mitigate costs and reduce environmental impacts.

HIGHLIGHTS

Summary of Results

Year ended December 31 ($ millions unless otherwise noted)	**2008**	2007	2006
Revenue	**9 386**	6 775	7 407
Production (thousands of bpd)	**228.0**	235.6	260.0
Average sales price ($/barrel)	**95.96**	74.01	68.03
Net earnings	**2 875**	2 474	2 775
Cash flow from operations [(1)]	**3 838**	3 143	3 903
Total assets	**25 795**	18 172	13 727
Cash used in investing activities	**6 996**	4 248	2 230
Net cash surplus (deficiency) before financing activities	**(2 555)**	(519)	2 113
Sales mix (light/heavy mix)	**43/57**	54/46	53/47
Cash operating costs ($/barrel) [(1)]	**38.50**	27.80	21.70
ROCE (%) [(1), (2)]	**35.5**	43.0	53.1
ROCE (%) [(1), (3)]	**21.8**	27.9	39.8

(1) Non-GAAP measure. See page 40.

(2) Excludes capitalized costs related to major projects in progress. Return on capital employed (ROCE) for our operating segments is calculated in a manner consistent with consolidated ROCE as reconciled in Non-GAAP Financial Measures.

(3) Includes capitalized costs related to major projects in progress.

2008 Overview

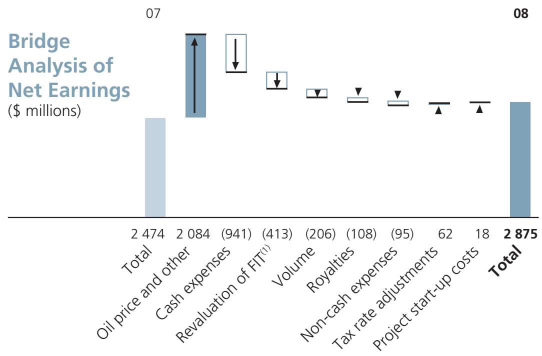
- Oil sands production averaged 228,000 bpd in 2008, compared to 235,600 bpd in 2007. Production was down year-over-year primarily as the result of upgrader reliability and bitumen production issues. In addition, an unplanned shutdown of facilities that supply hydrogen reduced production of higher-value sweet synthetic crude oil and diesel during the third quarter of 2008.
- Oil sands cash operating costs averaged $38.50 per barrel during 2008, compared to $27.80 per barrel in 2007. The higher costs in 2008 are primarily due to increases in operating expenses, natural gas input costs and third-party bitumen purchases being spread over lower production.

- On January 20, 2009, Suncor's Board of Directors approved a revised capital budget which deferred the company's growth projects in light of recent market conditions. With the revised plan, construction on the Voyageur upgrader and Firebag Stage 3 will be wound down and the projects placed in a "safe mode" pending resumption of expansion work. At this time, construction restart and completion targets for these projects, and start up and completion targets for other expansion projects, have not been determined. Capital growth plans will be reviewed on a quarterly basis in light of market conditions and updates provided as details are known.
- During 2008, progress was made on a variety of capital projects that are expected to benefit operational reliability, production and sales. The addition of a new $2.3 billion set of cokers to our upgrading complex, which increased design capacity to 350,000 bpd, was completed during the year. Other work included construction of a naphtha unit (which is intended to enhance product mix) which was approximately 60% complete at year-end, and the Steepbank extraction plant which was approximately 70% complete at year-end.
- During 2008, we continued to make progress on our Voyageur growth strategy. At December 31, 2008, we had spent approximately $7.0 billion out of the total Voyageur program budget of $20.6 billion.
- Production from Suncor's Firebag in-situ operations had been limited by regulators to 42,000 bpd due to sulphur emissions that exceeded regulatory limits in 2007. This production cap was lifted during the third quarter of 2008.

Analysis of Net Earnings

Net earnings were $2.875 billion in 2008, compared to $2.474 billion in 2007 (2006 – $2.775 billion). Excluding the impacts of income tax rate reductions on opening future income tax liabilities, net insurance proceeds received in 2006 (relating to the January 2005 fire) and project start-up costs, earnings were $2.899 billion in 2008, compared to $2.104 billion in 2007 (2006 – $2.140 billion).

Bridge Analysis of Net Earnings
($ millions)



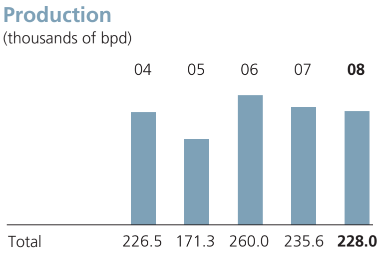
(1) Future income tax.

The increase in earnings primarily reflects strong price realizations due to high average benchmark WTI crude oil prices during the first three quarters of the year. This was partially offset by increased operating expenses, decreased production of higher-value sweet crude oil products, and significantly lower price realizations in the fourth quarter of 2008.

Oil sands average production was 228,000 bpd in 2008, compared to 235,600 bpd in 2007. Sales volumes in 2008 averaged 227,000 bpd, compared with 234,700 bpd in 2007. Lower sales volumes decreased 2008 net earnings by $206 million. Production and sales volumes were lower in 2008 due mainly to upgrader reliability and bitumen supply issues. This was partially offset by a shorter planned maintenance shutdown during 2008 (38 days in 2008, compared to a 50-day shutdown in 2007).

Sales price realizations averaged $95.96 per barrel in 2008 (including the impact of pretax hedging losses of $31 million), compared with $74.01 per barrel in 2007 (with pretax hedging losses of $5 million). The average sales price realization was favourably impacted by stronger WTI benchmark crude oil prices and strengthening differentials on our sweet crude blend and diesel products relative to WTI, partially offset by an increased discount to WTI for our sour crude blends and an increased proportion of lower priced sour products in our sales mix.

The net impact of the above sales mix and pricing factors increased net earnings by $2.084 billion in 2008.



Cash Expenses

Cash expenses, which include purchases of crude oil and products, operating, selling and general expenses, transportation and other costs, exploration expenses, and taxes other than income taxes, were $4.055 billion in 2008, compared to $2.782 billion in 2007 (2006 – $2.560 billion). Expenses increased year-over-year primarily due to higher maintenance expenditures aimed at improving reliability, increased energy input costs as a result of strong natural gas pricing, and a significant increase in purchases of both third-party bitumen and product related to transportation of sour crude shipments.

Overall, increased cash expenses reduced net earnings by $941 million.

Royalties

Alberta oil sands Crown royalties increased to $715 million in 2008, compared to $565 million in 2007 (2006 – $911 million). The increased royalty expense is due primarily to higher revenues resulting from strong WTI crude pricing during the first nine months of the year. This was partially offset by the impact of higher operating expenses, lower volumes, and higher capital expenditures eligible for deduction under Crown royalty formulas. Alberta oil sands Crown royalties are subject to completion of audits for 2008 and prior years. Changes to the estimated amounts previously recorded will be reflected in our financial statements on a prospective basis and may be significant. For a further discussion on Crown royalties, see page 15.

Non-Cash Expenses

Non-cash depreciation, depletion and amortization (DD&A) expense increased to $580 million in 2008 from $462 million in 2007 (2006 – $385 million). The increase primarily resulted from continued growth in the depreciable cost base after the commissioning of new assets throughout the year. Higher non-cash expenses decreased net earnings by $95 million.

Revaluation of Future Income Taxes

Reductions to the federal income tax rate in the second and fourth quarters of 2007 resulted in a total decrease of $413 million in the oil sands opening future income tax (FIT) liability balance, and a corresponding increase in the net earnings of the oil sands segment. There were no adjustments to income tax rates during 2008.

Cash Operating Costs

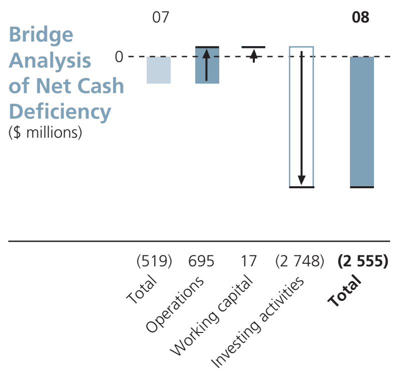
Cash operating costs increased to $3.212 billion in 2008, compared to $2.391 billion in 2007. On a per barrel basis, these costs increased to $38.50 per barrel from $27.80 per barrel in 2007. The increase in cash operating costs per barrel is a result of increases in operating expenses, natural gas input costs and third-party bitumen purchases being spread over lower production. Refer to page 40 for further details on cash operating costs as a non-GAAP financial measure, including the calculation and reconciliation to GAAP measures.

Net Cash Surplus (Deficiency) Analysis

Cash flow from operations was $3.838 billion in 2008, compared to $3.143 billion in 2007 (2006 – $3.903 billion). The increase was primarily due to the same factors that impacted net earnings.

Cash flow used in investing activities increased to $6.996 billion in 2008 from $4.248 billion in 2007 (2006 – $2.230 billion). During 2008, capital spending related primarily to our Voyageur program, Steepbank extraction plant and naphtha unit projects.

Combined, the above factors resulted in a net cash deficiency of $2.555 billion in 2008, compared with a deficiency of $519 million in 2007 (2006 – net cash surplus of $2.113 billion).



Future Expansion

In 2001, Suncor announced plans to pursue a multi-phased growth strategy to increase production capacity at its oil sands plant from 225,000 barrels per day (bpd) to 550,000 bpd in 2012.

The first step in that plan was completed in 2005 when Suncor increased production capacity by 35,000 bpd (bringing total production capacity to 260,000 bpd). During 2008, we completed a $2.3 billion expansion to one of our two upgraders, increasing production design capacity to 350,000 bpd.

Suncor's Board of Directors approved the final phase of this multi-staged growth strategy in January 2008. Our total estimated investment of $20.6 billion for the Voyageur program was comprised of $11.6 billion targeted for construction of a third upgrader and $9 billion for expanding bitumen supply at our Firebag in-situ operation.

In response to current market uncertainty, we announced an update to our Voyageur program schedule on January 20, 2009. A revised capital budget has deferred the company's growth projects. With the new plan, construction on the Voyageur upgrader and Firebag Stage 3 will be wound down and the projects placed in a "safe mode" pending resumption of expansion work. At this time, construction restart and completion targets for these projects, and start up and completion targets for other expansion projects, have not been determined. Capital growth plans will be reviewed on a quarterly basis in light of market conditions and updates provided as details are known.

For further details, see the Significant Capital Projects table on page 14.

Risk Factors Affecting Performance

Our financial and operating performance is potentially affected by a number of factors, including, but not limited to, the following:

- Our ability to finance oil sands growth and sustaining capital expenditures in a volatile commodity pricing and credit environment. Also refer to Liquidity and Capital Resources on page 12.
- Production reliability risk. Our ability to reliably operate our oil sands facilities in order to meet production targets. We implemented planned maintenance shutdowns in 2008 that are expected to improve reliability.
- Ability to manage production operating costs. Operating costs could be impacted by inflationary pressures on labour, volatile pricing for natural gas used as an energy source in oil sands processes, and planned and unplanned maintenance. We continue to address these risks through such strategies as application of technologies that help manage operational workforce demand, offsetting natural gas purchases through internal production, investigation of technologies that mitigate reliance on natural gas as an energy source, and an increased focus on preventative maintenance.
- Our ability to complete projects both on time and on budget. This could be impacted by competition from other projects (including other oil sands projects) for goods and services and demands on the Fort McMurray infrastructure (including housing, roads and schools). We continue to address these issues through a comprehensive recruitment and retention strategy, working with the community to determine infrastructure needs, designing oil sands expansion to reduce unit costs, seeking strategic alliances with service providers and maintaining a strong focus on engineering, procurement and project management.
- Potential changes in the demand for refinery feedstock and diesel fuel. Our strategy is to reduce the impact of this issue by entering into long-term supply agreements with major customers, expanding our customer base and offering a variety of blends of refinery feedstock to meet customer specifications.
- Volatility in crude oil and natural gas prices, foreign exchange rates and the light/heavy and sweet/sour crude oil differentials. Current prices are well below the average price realized in 2008. We mitigate some of the risk associated with changes in commodity prices through the use of derivative financial instruments (see page 17).
- Logistical constraints and variability in market demand, which can impact crude movements. These factors can be difficult to predict and control.
- Changes to royalty and tax legislation and agreements that could impact our business. While fiscal regimes in Alberta and Canada are generally stable relative to many global jurisdictions, royalty and tax treatments are subject to periodic review, the outcome of which is not predictable and could result in changes to the company's planned investments, and rates of return on existing investments.
- Our relationship with our trade unions. Work disruptions have the potential to adversely affect oil sands operations and growth projects. The Communications, Energy and Paperworkers Union Local 707 represents approximately 2,300 oil sands employees. The current collective agreement with the union expires on April 30, 2010.

Additional risks impacting Suncor's general operations can be seen at Risk Factors Affecting Performance on page 19. Additional risks, assumptions and uncertainties are discussed on page 42 under Forward-Looking Information.

NATURAL GAS

Suncor's natural gas business, operating primarily in western Canada, acts as a natural price hedge against the company's purchases for internal consumption at our oil sands operations.

Natural gas strategy focuses on:

- Building competitive operating areas.
- Improving base business efficiency, with a focus on operational excellence and work site safety.
- Pursuing new, low-capital business opportunities.

HIGHLIGHTS

Summary of Results

Year ended December 31 ($ millions unless otherwise noted)	**2008**	2007	2006
Revenue	**754**	553	578
Natural gas production (mmcf/d)	**202**	196	191
Average natural gas sales price ($/mcf)	**8.23**	6.32	7.15
Net earnings	**89**	25	106
Cash flow from operations[1]	**368**	248	281
Total assets	**1 862**	1 811	1 503
Cash used in investing activities	**316**	532	443
Net cash surplus (deficiency) before financing activities	**94**	(262)	(189)
ROCE (%)[1,2]	**7.7**	2.5	14.9

(1) Non-GAAP Measure. See page 40.

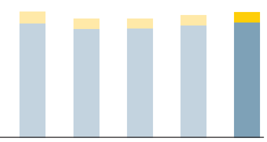
(2) ROCE for Suncor operating segments is calculated in a manner consistent with consolidated ROCE as reconciled in Non-GAAP Financial Measures.

2008 Overview

- Total production averaged 220 million cubic feet equivalent per day (mmcfe/d) in 2008, compared to 215 mmcfe/d in 2007. Production during 2008 comprised 92% natural gas and 8% natural gas liquids and crude oil.
- Purchases of natural gas for internal consumption at our oil sands operations were approximately 143 million cubic feet per day (mmcf/d) during 2008, compared to natural gas production of 202 mmcf/d in 2008.
- During the second quarter of 2008, Suncor disposed of Arctic properties for proceeds of $24 million.
- In September, Suncor, together with a partner, successfully bid for a large offshore parcel in the Newfoundland and Labrador Offshore Area. This land is adjacent and complementary to an existing holding in the Bjarni area and provides Suncor with a long-term option for future potential natural gas growth. In order to retain the lands, the exploration license requires Suncor to commit to spend net $30 million in exploration work on the lands within six years.

Production

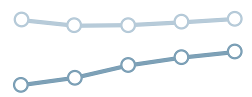
(millions of cubic feet equivalent per day)



	04	05	06	07	**08**
Natural gas liquids and crude oil	21	19	18	19	**18**
Natural gas	200	190	191	196	**202**
Total	221	209	209	215	**220**

Natural Gas Production vs. Purchases

(mmcf/d)



	04	05	06	07	**08**
Production	200	190	191	196	**202**
Purchases[1]	84	97	119	133	**143**

(1) Purchases for internal consumption at our oil sands operations.

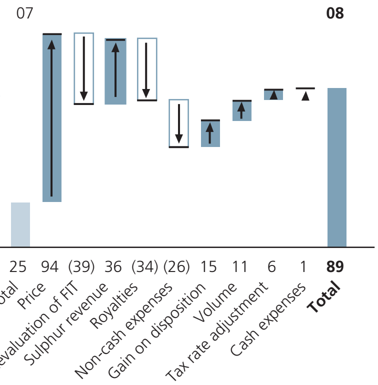
Analysis of Net Earnings

Natural gas net earnings were $89 million in 2008, compared to $25 million in 2007 (2006 – $106 million). Excluding the impact of income tax rate reductions on opening future income tax liabilities, earnings for 2008 were $89 million, compared to a loss of $14 million in 2007 (2006 – net earnings of $53 million). The increase in earnings was primarily due to higher revenues driven by stronger price realizations including higher sulphur prices and increased production, in addition to a gain on sale of non-core assets and lower dry hole costs. These factors were partially offset by higher royalties and increased depreciation, depletion and amortization expense resulting from increased production from areas with larger capital bases relative to assigned reserves.

The average realized price for natural gas was $8.23 per thousand cubic feet (mcf) in 2008, compared to an average of $6.32 per mcf in 2007, reflecting higher benchmark natural gas prices in the first three quarters of 2008. There was also an increase in price realizations for crude oil and natural gas liquids resulting from higher benchmark prices for those products in the first three quarters of 2008. The net impact of the price variance was an increase in net earnings of $94 million. Strong pricing was also experienced on our sulphur products, resulting in a $36 million positive impact to net earnings.

Natural gas total production was 220 mmcfe/d in 2008, compared to 215 mmcfe/d in the prior year. The increase in 2008 production was primarily due to increased volumes from positive drilling results, offset by natural declines. Increased production volumes positively impacted 2008 net earnings by $11 million.

Bridge Analysis of Net Earnings
($ millions)



Cash Expenses

Operating costs, including general and administrative expenses, were $155 million in 2008, a slight increase from $151 million in 2007 (2006 – $119 million). An increase in lifting costs resulting from increased volumes from areas with higher processing costs and reduced third-party processing credits, was partially offset by a reduction in administration costs.

Exploration expenses were $73 million in 2008, compared to $82 million in 2007 (2006 – $82 million). The decrease was mainly due to lower dry hole costs in 2008.

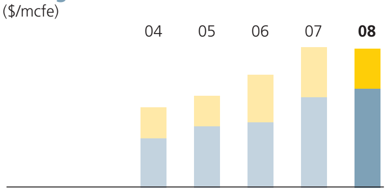
Non-Cash expenses

DD&A expense was $225 million in 2008, compared to $189 million in 2007 (2006 – $152 million). The increase was due to production increases in areas with a higher cost structure.

Royalties

Royalties on production of natural gas, liquids and sulphur were $175 million ($2.17 per thousand cubic feet equivalent (mcfe)) in 2008, an increase from $126 million ($1.61 per mcfe) in 2007 (2006 – $127 million; $1.67 per mcfe). The current year saw both higher production and higher sales price realizations. In 2008 the government of Alberta announced the New Royalty Framework which changed the royalty rates beginning January 1, 2009. Natural gas generated about 76% of its production from Alberta in 2008. For a further discussion on Crown royalties, see page 15.

Lifting and Administration Costs
($/mcfe)

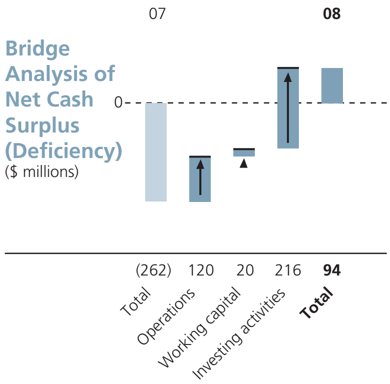


	04	05	06	07	08
Administration	0.43	0.42	0.67	0.70	**0.56**
Lifting	0.69	0.86	0.91	1.26	**1.38**
Total	1.12	1.28	1.58	1.96	**1.94**

Net Cash Surplus/Deficiency Analysis

Natural gas net cash surplus was $94 million in 2008, compared with a $262 million deficiency in 2007 (2006 – $189 million deficiency). Cash flow from operations increased to $368 million compared with $248 million in the prior year (2006 – $281 million), mainly due to increased revenues.

Cash used in investing activities decreased to $316 million, compared with $532 million in 2007 (2006 – $443 million) primarily due to a large purchase of developed and undeveloped land made in 2007, as well as reduced drilling activity in 2008.



Risk Factors Affecting Performance

Our financial and operating performance is potentially affected by a number of factors, including, but not limited to, the following:

- Consistently and competitively finding and developing reserves that can be brought on stream economically.
- Our ability to finance capital investment to replace reserves or increase processing capacity in a volatile commodity pricing and credit environment. Also refer to Liquidity and Capital Resources on page 12.
- Volatility in natural gas and liquids prices is not predictable and can significantly impact revenues. Current prices are well below the average price realized in 2008.
- The impact of market demand for land. Market demand also influences the cost and available opportunities for acquisitions.
- The impact of market demand for labour and equipment, which in a heated exploration and development market, could increase costs and/or cause delays to projects for natural gas and its competitors.
- Risks and uncertainties associated with consulting with stakeholders and obtaining regulatory approval for exploration and development activities in our operating areas. These risks could increase costs and/or cause delays to or cancellation of projects.
- Risks and uncertainties associated with weather conditions, which can shorten the winter drilling season and impact the spring and summer drilling program, which may result in increased costs and/or delays in bringing on new production.

Additional risks impacting Suncor's general operations can be seen at Risk Factors Affecting Performance on page 19. Additional risks, assumptions and uncertainties are discussed on page 42 under Forward-Looking Information.

REFINING AND MARKETING

Refining and marketing operates an 85,000 barrel per day (bpd) capacity refinery in Sarnia, Ontario and a 93,000 bpd capacity refining complex in Commerce City, Colorado, and markets refined products to industrial, wholesale and commercial customers primarily in Ontario and Colorado. Through a combination of joint venture-operated, company-owned and branded-reseller retail stations, we market products to retail customers in Ontario and the Denver area. Assets also include a 200-million litre per year ethanol plant in St. Clair, Ontario, the 480-kilometre Rocky Mountain pipeline system, the 140-kilometre Centennial pipeline system, two product terminals in Ontario, and two product terminals in Colorado. This business also supports Suncor's sustainability goals by managing investment in wind energy projects and developing strategies to reduce greenhouse gas emissions.

The refining and marketing business also encompasses third-party energy marketing and trading activities, as well as providing marketing services for the sale of crude oil, natural gas, refined products and by-products from the oil sands and natural gas segments.

Refining and marketing's strategy is focused on:

- Enhancing the profitability of refining operations by improving reliability and product yields and enhancing operational flexibility to process a variety of feedstock, including crude oil streams from oil sands operations.
- Creating downstream market opportunities to capture greater long-term value from oil sands production.
- Reducing costs through the application of technologies, economies of scale, an increased focus on reliability through carefully managed maintenance scheduling, strategic alliances with key suppliers and customers and continuous improvement of operations.
- Increasing the profitability and efficiency of our retail networks.

HIGHLIGHTS

Summary of Results

Year ended December 31 ($ millions unless otherwise noted)	**2008**	2007	2006
Revenue	**21 371**	11 805	9 310
Refined product sales (millions of litres)			
Gasoline	**5 819**	6 132	5 804
Total	**11 529**	12 228	10 803
Net earnings breakdown:			
Downstream earnings	**58**	403	239
Energy marketing and trading activities	**71**	35	22
Inventory valuation and marketing expense	**(78)**	6	(17)
Total net earnings	**51**	444	244
Cash flow from operations [1]	**278**	716	451
Total assets	**4 666**	4 825	4 219
Cash used in investing activities	**(256)**	(491)	(787)
Net cash deficiency before financing activities	**(8)**	(29)	(446)
ROCE (%) [1, 2]	**1.7**	20.0	19.3
ROCE (%) [1, 3]	**1.7**	17.4	12.2

(1) Non-GAAP measure. See page 40.

(2) Excludes capitalized costs related to major projects in progress. Return on capital employed (ROCE) for our operating segments is calculated in a manner consistent with consolidated ROCE as reconciled in Non-GAAP Financial Measures.

(3) Includes capitalized costs related to major projects in progress.

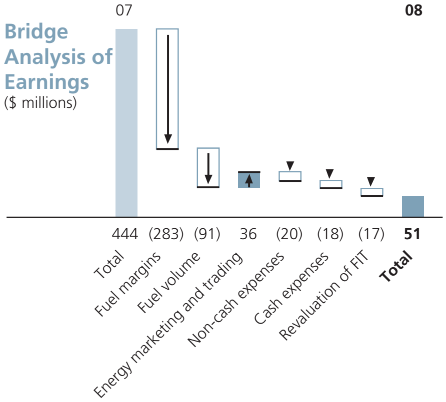
2008 Overview

- Lower gasoline margins and demand, weak asphalt and residual pricing, and a decline in crude oil prices at the end of 2008 that reduced the value of our inventories negatively impacted earnings in 2008. This was partially offset by stronger distillate fuel margins.
- Significantly increased energy marketing and trading activities as a result of the implementation and further development of crude and natural gas trading strategies to maximize value from proprietary production and for refinery optimization and gain market expertise and market presence. Increased earnings from these activities were largely the result of gains on crude oil financial contracts.
- During the second quarter, additional capital equipment improvements were identified that will be required before the Sarnia refinery can achieve full benefit from modifications made in 2007 to increase sour synthetic crude capacity at the facility. We are currently evaluating our options relating to these capital expenditures.
- Refinery utilization levels were slightly lower due to softening demand for petroleum products as well as additional scheduled and unscheduled maintenance.
- The observed performance of our Sarnia refinery in 2008, after completion of our diesel desulphurization and oil sands integration project in 2007, has enabled us to upwardly revise our nameplate capacity to 85,000 bpd from the previously disclosed 70,000 bpd. Starting January 1, 2009, refinery utilization will be calculated using the 85,000 bpd capacity. The Commerce City refining capacity has also been increased from 90,000 bpd to 93,000 bpd effective January 1, 2009.

Analysis of Net Earnings

Refining and marketing results include the impact of our third-party energy marketing and trading activities that are discussed separately on page 38.

Refining and marketing's net earnings decreased to $51 million in 2008 from $444 million in 2007 (2006 – $244 million). This decrease was primarily due to reduced margins on gasoline, asphalt and other heavy products, as well as softening demand for petroleum products due initially to historically high prices and later to general economic conditions. This was partially offset by increased margins on distillate fuels.



Volumes

Total sales volumes averaged 31.5 $10^3m^3/d$ (thousands of cubic metres per day), compared to 33.5 $10^3m^3/d$ in 2007. The decrease in sales was the result of softening demand for petroleum products. Total gasoline sales volumes through our Sunoco and Phillips 66® branded retail network were 1,700 million litres in 2008, down from 1,900 million litres in 2007.

Fuel Margins

Gasoline margins were significantly lower in 2008 as a result of reduced demand for gasoline. We also encountered reduced margins on asphalt mainly due to the high crude price environment. Asphalt margins did recover in the fourth quarter as the price of crude lowered. These factors were partially offset by increased margins on distillate fuels resulting from strong market demand for diesel and jet fuel throughout the year. Crude and product purchases were $8.074 billion in 2008, compared to $6.250 billion in 2007 (2006 – $5.297 billion). The increase was primarily the result of higher crude oil prices during the first three quarters of 2008.

Refinery Utilization

Overall crude refinery utilization averaged 97% in 2008, compared with 98% in 2007. The decrease in refinery utilization was primarily the result of softening demand for petroleum products and additional scheduled and unscheduled maintenance.

Cash and Non-Cash Expenses

Overall, cash and non-cash operating expenses increased by $38 million after-tax in 2008. Cash expenses increased by $18 million after-tax in 2008, primarily due to higher energy and employee related costs. Non-cash expenses increased by $20 million after-tax in 2008, due to increased depreciation, depletion and amortization expense mainly resulting from a full year's depreciation being taken on both the Sarnia refinery oil sands integration project that was completed in 2007 and a comprehensive maintenance turnaround at Sarnia that was completed in the fall of 2007.

Related Party Transactions

The Pioneer and UPI retail facilities joint ventures and the Sun Petrochemicals Company (SPC) joint venture are considered to be related parties to Suncor under Canadian GAAP. Refining and marketing supplies refined petroleum products to the Pioneer and UPI joint ventures, and petrochemical products to SPC. Suncor has a separate supply agreement with each of Pioneer, UPI and SPC.

The following table summarizes our related party transactions with Pioneer, UPI and SPC, after eliminations, for the year. These transactions are in the normal course of operations and have been conducted on the same terms as would apply with third parties.

($ millions)	**2008**	2007	2006
Operating revenues			
Sales to refining and marketing joint ventures:			
Refined products	**368**	329	294
Petrochemicals	**188**	163	136

At December 31, 2008, amounts due from refining and marketing joint ventures were $13 million, compared to $17 million at December 31, 2007.

Energy Marketing and Trading Activities

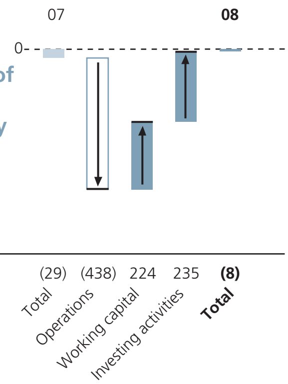
These activities involve marketing and trading of crude oil, natural gas, refined products and by-products, and the use of financial derivatives. These activities resulted in net earnings after-tax of $71 million in 2008 compared to $35 million in 2007 (2006 – $22 million). The higher earnings in 2008 compared to 2007 were the result of gains on crude oil financial contracts. For further details on our energy marketing and trading activities, see page 17.

Net Cash Deficiency Analysis

Refining and marketing's net cash deficiency was $8 million in 2008 compared to a net cash deficiency of $29 million in 2007 (2006 – $446 million). Cash flow from operations was $278 million in 2008 compared to $716 million in 2007 (2006 – $451 million). The decrease was primarily due to the same factors that impacted net earnings.

Cash used in investing activities was $256 million in 2008 compared to $491 million in 2007 (2006 – $787 million). Capital expenditures in 2008 were significantly lower than the previous year, as the work related to the Sarnia oil sands integration projects was completed in 2007. Capital spending in 2008 related mainly to planned refinery shutdowns as well as other regulatory related project spending.

Bridge Analysis of Net Cash Deficiency
($ millions)



Risk Factors Affecting Performance

Our financial and operating performance is potentially affected by a number of factors, including, but not limited to, the following:

- Management expects that fluctuations in demand and supply for refined products, margin and price volatility, and market competition, including potential new market entrants, will continue to impact the business environment.
- There are certain risks associated with the execution of capital projects, including the risk of cost overruns. Numerous risks and uncertainties can affect construction schedules, including the availability of labour and other impacts of competing projects drawing on the same resources during the same time period.

Additional risks impacting Suncor's general operations can be seen at Risk Factors Affecting Performance on page 19. Additional risks, assumptions and uncertainties are discussed on page 42 under Forward-Looking Information.

OUTLOOK

During 2009, management will focus on the following priorities:

- **Operational excellence.** Focusing on operational excellence to enhance personal and process safety management, environmental excellence and sustainability, reliability, and people.
- **Achieve annual oil sands production of 300,000 bpd (+5%/ – 10%) at a cash operating cost average of $33 to $38 per barrel.** Increased bitumen supply and reliability improvements in extraction and upgrading are expected to increase production from existing capital assets.
- **Target production from our natural gas business of 210 mmcf equivalent per day (+5%/ – 5%).** Continue to pursue exploration and development of natural gas assets to offset natural gas purchases for internal consumption at our oil sands operations.
- **Continue to focus on safety.** Continue efforts to identify and reduce potential process safety hazards and implement enhanced company-wide occupational hygiene and health standards.
- **Maintain a strong balance sheet.** Planned capital spending has been reduced to $3 billion for 2009, with major growth capital investment deferred. Strategic hedging of 60% of target 2009 production provides a degree of insurance to the balance sheet.
- **Continue efforts to reduce environmental impact intensity.** We expect to complete the sulphur recovery plant at Firebag in mid-2009 with start-up and commissioning taking place throughout the remainder of the year, while work will continue on developing accelerated reclamation technology. Improved oil sands plant reliability is expected to contribute to lower energy and emissions intensity.

Suncor's outlook provides management's targets for 2009 in certain key areas of the company's business. Users of this information are cautioned that the actual results in 2009 may vary materially from the targets disclosed. Readers are cautioned against placing undue reliance on this outlook.

	2009 Full-Year Outlook
Oil Sands	
Production (1) (bpd)	300,000 (+5%/ – 10%)
Sales	
Diesel	11%
Sweet	39%
Sour	48%
Bitumen	2%
Realization on crude sales basket	WTI @ Cushing less Cdn$4.50 to Cdn$5.50 per barrel
Cash operating costs (2)	$33 to $38 per barrel
Natural Gas	
Production (3) (mmcf equivalent per day)	210 (+5%/ – 5%)
Natural gas	92%
Liquids	8%

(1) Includes volumes transferred to Suncor for processing for which the company receives a processing fee. Volumes received under this arrangement are not included as purchases for financial statement presentation.

(2) Cash operating cost estimates are based on the following assumptions: (i) production volumes and sales mix as described in the table above; and (ii) a natural gas price of $7.10 per gigajoule at AECO. This goal also includes costs incurred for third-party bitumen processing. Cash operating costs per barrel are not prescribed by Canadian generally accepted accounting principles (GAAP). This non-GAAP financial measure does not have any standardized meaning and therefore is unlikely to be comparable to similar measures presented by other companies. Suncor includes this non-GAAP financial measure because investors may use this information to analyze operating performance. This information should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP. See Non-GAAP Financial Measures on page 40.

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

The 2009 outlook is based on Suncor's current estimates, projections and assumptions for the 2009 fiscal year and is subject to change. Assumptions are based on management's experience and perception of historical trends, current conditions, anticipated future developments and other factors believed to be relevant. Assumptions of the 2009 outlook include implementing reliability and operational efficiency initiatives which we expect to minimize unplanned maintenance in 2009.

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

- **Bitumen supply.** Ore grade quality, unplanned mine equipment and extraction plant maintenance, tailings storage and in-situ reservoir performance could impact 2009 production targets. Production could also be impacted by the availability of third-party bitumen.
- **Performance of recently commissioned upgrading facilities.** Production rates while new equipment is being lined out are difficult to predict and can be impacted by unplanned maintenance.
- **Unplanned maintenance.** Production estimates could be impacted if unplanned work is required at any of our mining, production, upgrading, refining or pipeline assets.
- **Crude oil hedges.** Suncor has hedging agreements for approximately 60% of targeted production in 2009 and for 50,000 bpd in 2010.
- **Market instability.** Suncor's ability to borrow in the capital debt markets at acceptable rates may be affected by market instability.

For additional information on risk factors that could cause actual results to differ, please see page 19.

NON-GAAP FINANCIAL MEASURES

Certain financial measures referred to in this MD&A are not prescribed by Canadian generally accepted accounting principles (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 (dollars and per share amounts), return on capital employed (ROCE), 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 Canadian GAAP.

Cash Flow from Operations per Common Share

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 our Consolidated Financial Statements.

For the year ended December 31	**2008**	2007	2006
Cash flow from operations ($ millions)	**4 463**	4 009	4 524
Weighted average number of common shares outstanding – basic (millions of shares)	**932**	922	918
Cash flow from operations – basic ($ per share)	**4.79**	4.35	4.93

ROCE

For the year ended December 31 ($ millions, except ROCE)		**2008**	2007	2006
Adjusted net earnings				
Net earnings		**2 137**	2 983	2 969
Add: after-tax financing expenses (income)		**852**	(179)	26
	A	**2 989**	2 804	2 995
Capital employed – beginning of year				
Short-term and long-term debt, less cash and cash equivalents		**3 248**	1 849	2 868
Shareholders' equity		**11 896**	9 084	6 130
	B	**15 144**	10 933	8 998
Capital employed – end of year				
Short-term and long-term debt, less cash and cash equivalents		**7 226**	3 248	1 849
Shareholders' equity		**14 523**	11 896	9 084
	C	**21 749**	15 144	10 933
Average capital employed	(B+C)/2=D	**18 447**	13 039	9 966
Average capitalized costs related to major projects in progress	E	**5 149**	3 454	2 476
ROCE (%)	A/(D – E)	**22.5**	29.3	40.0

Oil Sands Operating Costs – Total Operations

	2008		2007		2006	
(unaudited)	**$ millions**	**$/barrel**	$ millions	$/barrel	$ millions	$/barrel
Operating, selling and general expenses	**3 124**		2 384		2 212	
Less: natural gas costs, inventory changes, stock-based compensation and other	**(524)**		(301)		(375)	
Less: non-monetary transactions	**(111)**		(102)		(126)	
Accretion of asset retirement obligations	**55**		40		28	
Taxes other than income taxes	**80**		55		36	
Cash costs	**2 624**	**31.45**	2 076	24.15	1 775	18.70
Natural gas	**438**	**5.25**	307	3.55	276	2.90
Imported bitumen (net of other reported product purchases)	**150**	**1.80**	8	0.10	6	0.10
Cash operating costs	**3 212**	**38.50**	2 391	27.80	2 057	21.70
Project start-up costs	**35**	**0.40**	60	0.95	38	0.40
Total cash operating costs	**3 247**	**38.90**	2 451	28.75	2 095	22.10
Depreciation, depletion and amortization	**580**	**6.95**	462	5.40	385	4.05
Total operating costs	**3 827**	**45.85**	2 913	34.15	2 480	26.15
Production (thousands of barrels per day)	**228.0**		235.6		260.0	

Oil Sands Operating Costs – In-Situ Bitumen Production Only

	2008		2007		2006	
(unaudited)	**$ millions**	**$/barrel**	$ millions	$/barrel	$ millions	$/barrel
Operating, selling and general expenses	**334**		273		209	
Less: natural gas costs and inventory changes	**(168)**		(134)		(103)	
Taxes other than income taxes	**12**		7		4	
Cash costs	**178**	**13.00**	146	10.85	110	8.95
Natural gas	**168**	**12.30**	134	9.90	103	8.35
Cash operating costs	**346**	**25.30**	280	20.75	213	17.30
In-situ (Firebag) start-up costs	**9**	**0.65**	—	—	21	1.70
Total cash operating costs	**355**	**25.95**	280	20.75	234	19.00
Depreciation, depletion and amortization	**87**	**6.35**	83	6.20	68	5.55
Total operating costs	**442**	**32.30**	363	26.95	302	24.55
Production (thousands of barrels per day)	**37.4**		36.9		33.7	

Legal Notice – Forward-Looking Information

This Management's Discussion and Analysis contains certain forward-looking statements and other information that are based on Suncor's current expectations, estimates, projections and assumptions made by the company in light of its experience and its perception of historical trends.

All statements and other information that address expectations or projections about the future, including statements about Suncor's strategy for growth, expected future expenditures, commodity prices, costs, schedules, production volumes, operating and financial results, and expected impact of future commitments are forward-looking statements. Some of the forward-looking statements may be identified by words like "expects," "anticipates," "estimates," "plans," "scheduled," "intends," "believes," "projects," "indicates," "could," "focus," "vision," "goal," "outlook," "proposed," "target," "objective," and similar expressions. These statements are not guarantees of future performance and involve a number of risks and uncertainties, some that are similar to other oil and gas companies and some that are unique to Suncor. Suncor's actual results may differ materially from those expressed or implied by its forward-looking statements and readers are cautioned not to place undue reliance on them.

Suncor's outlook includes a production range of +5%/−10% based on our current expectations, estimates, projections and assumptions. Uncertainties in the estimating process and the impact of future events may cause actual results to differ, in some cases materially, from our estimates. Assumptions are based on management's experience and perception of historical trends, current conditions, anticipated future developments and other factors believed to be relevant. For a description of assumptions and risk factors specifically related to the 2009 outlook, see page 40.

The risks, uncertainties and other factors that could influence actual results include, but are not limited to, market instability affecting Suncor's ability to borrow in the capital debt markets at acceptable rates; availability of third-party bitumen; success of hedging strategies, maintaining a desirable debt to cashflow ratio; changes in the general economic, market and business conditions; fluctuations in supply and demand for Suncor's products; commodity prices, interest rates and currency exchange rates; Suncor's ability to respond to changing markets and to receive timely regulatory approvals; the successful and timely implementation of capital projects including growth projects and regulatory projects (for example, the emissions reduction modifications at our Firebag in-situ development); the accuracy of cost estimates, some of which are provided at the conceptual or other preliminary stage of projects and prior to commencement or conception of the detailed engineering needed to reduce the margin of error and increase the level of accuracy; the integrity and reliability of Suncor's capital assets; the cumulative impact of other resource development; the cost of compliance with current and future environmental laws; the accuracy of Suncor's reserve, resource and future production estimates and its success at exploration and development drilling and related activities; the maintenance of satisfactory relationships with unions, employee associations and joint venture partners; competitive actions of other companies, including increased competition from other oil and gas companies and from companies that provide alternative sources of energy; labour and material shortages; uncertainties resulting from potential delays or changes in plans with respect to projects or capital expenditures; actions by governmental authorities including the imposition of taxes or changes to fees and royalties; changes in environmental and other regulations (for example, the Government of Alberta's review of the unintended consequences of the proposed Crown royalty regime, and the Government of Canada's current review of greenhouse gas emission regulations); the ability and willingness of parties with whom we have material relationships to perform their obligations to us; and the occurrence of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting Suncor or other parties whose operations or assets directly or indirectly affect Suncor. These 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.

MANAGEMENT'S STATEMENT OF RESPONSIBILITY FOR FINANCIAL REPORTING

The management of Suncor Energy Inc. is responsible for the presentation and preparation of the accompanying consolidated financial statements of Suncor Energy Inc. on pages 47 to 86 and all related financial information contained in this Annual Report, including Management's Discussion and Analysis.

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles. They include certain amounts that are based on estimates and judgments relating to matters not concluded by year-end. Financial information presented elsewhere in this Annual Report is consistent with that contained in the consolidated financial statements.

In management's opinion, the consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the significant accounting policies adopted by management as summarized on pages 47 to 51. If alternate accounting methods exist, management has chosen those policies it deems the most appropriate in the circumstances. In discharging its responsibilities for the integrity and reliability of the financial statements, management maintains and relies upon a system of internal controls designed to ensure that transactions are properly authorized and recorded, assets are safeguarded against unauthorized use or disposition and liabilities are recognized. These controls include quality standards in hiring and training of employees, formalized policies and procedures, a corporate code of conduct and associated compliance program designed to establish and monitor conflicts of interest, the integrity of accounting records and financial information among others, and employee and management accountability for performance within appropriate and well-defined areas of responsibility.

The system of internal controls is further supported by the professional staff of an internal audit function who conduct periodic audits of the company's financial reporting.

The company retains independent petroleum consultants, GLJ Petroleum Consultants Ltd., to conduct independent evaluations of the company's oil and gas reserves and resources.

The Audit Committee of the Board of Directors, currently composed of five independent directors, reviews the effectiveness of the company's financial reporting systems, management information systems, internal control systems and internal auditors. It recommends to the Board of Directors the external auditors to be appointed by the shareholders at each annual meeting and reviews the independence and effectiveness of their work. In addition, it reviews with management and the external auditors any significant financial reporting issues, the presentation and impact of significant risks and uncertainties, and key estimates and judgments of management that may be material for financial reporting purposes. The Audit Committee appoints the independent petroleum consultants. The Audit Committee meets at least quarterly to review and approve interim financial statements prior to their release, as well as annually to review Suncor's annual financial statements and Management's Discussion and Analysis, Annual Information Form/Form 40-F, and annual reserves and resource estimates, and recommend their approval to the Board of Directors. The internal auditors and PricewaterhouseCoopers LLP have unrestricted access to the company, the Audit Committee and the Board of Directors.

Richard L. George
President and
Chief Executive Officer

J. Kenneth Alley
Senior Vice President and
Chief Financial Officer

February 25, 2009

The following report is provided by management in respect of the Company's internal control over financial reporting (as defined in Rule13a-15(f) under the U.S. Securities Exchange Act of 1934):

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

1. Management is responsible for establishing and maintaining adequate internal control over the Company's financial reporting.
2. Management has used the Committee of Sponsoring Organizations of the Treadway Commission (COSO) framework in Internal Control – Integrated Framework to evaluate the effectiveness of the Company's internal control over financial reporting.
3. Management has assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2008, and has concluded that such internal control over financial reporting was effective as of that date. Additionally, based on this assessment, management determined that there were no material weaknesses in internal control over financial reporting as of December 31, 2008. Because of inherent limitations, systems of internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.
4. The effectiveness of the Company's internal control over financial reporting as of December 31, 2008 has been audited by PricewaterhouseCoopers LLP, independent auditors, as stated in their report which appears herein.

Richard L. George
President and
Chief Executive Officer

J. Kenneth Alley
Senior Vice President and
Chief Financial Officer

February 25, 2009

INDEPENDENT AUDITORS' REPORT

TO THE SHAREHOLDERS OF SUNCOR ENERGY INC.

We have completed integrated audits of Suncor Energy Inc.'s 2008, 2007 and 2006 consolidated financial statements and of its internal control over financial reporting as at December 31, 2008. Our opinions, based on our audits, are presented below.

Consolidated financial statements

We have audited the accompanying consolidated balance sheets of Suncor Energy Inc. ("the company") as at December 31, 2008 and December 31, 2007, and the related consolidated statements of earnings and comprehensive income, of cash flows and of changes in shareholders' equity for each of the years in the three year period ended December 31, 2008. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits of the company's financial statements as at December 31, 2008 and 2007 and for each of the years in the three year period ended December 31, 2008 in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. A financial statement audit also includes assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the company as at December 31, 2008 and December 31, 2007 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2008 in accordance with Canadian generally accepted accounting principles.

Internal control over financial reporting

We have also audited the company's internal control over financial reporting as at December 31, 2008, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the company maintained, in all material respects, effective internal control over financial reporting as at December 31, 2008 based on criteria established in Internal Control – Integrated Framework issued by the COSO.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta

February 25, 2009

COMMENTS BY AUDITORS FOR U.S. READERS ON CANADA – U.S. REPORTING DIFFERENCES

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is a change in accounting principles that has a material effect on the comparability of the company's consolidated financial statements, such as the changes described in Summary of Significant Accounting Policies and in Note 1 to the consolidated financial statements. Our report to the shareholders dated February 25, 2009 is expressed in accordance with Canadian reporting standards, which do not require a reference to such a change in the Auditors' Report when the change is properly accounted for and adequately disclosed in the consolidated financial statements.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta

February 25, 2009

SUNCOR ENERGY INC.
SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Suncor Energy Inc. is a Canadian integrated energy company comprised of three operating segments: oil sands, natural gas, and refining and marketing.

Oil sands includes the production of light sweet and light sour crude oil, diesel fuel and various custom blends from oil sands in the Athabasca region of northeastern Alberta, and the marketing of these products substantially in Canada and the United States.

Natural gas includes the exploration, acquisition, development, production, transportation and marketing of natural gas, natural gas liquids and crude oil in Canada and the United States.

Refining and marketing includes the manufacturing, transportation and marketing of petroleum, petrochemical and biofuel products from our Canadian and United States operations. Canadian activities are conducted primarily in Ontario and Quebec, while activities in the United States are primarily in Colorado.

In addition to the operating segments outlined above, we also report a corporate segment which includes the activities not directly attributable to an operating segment, as well as those of our self-insurance entity.

The significant accounting policies of the company are summarized below:

(a) Principles of Consolidation and the Preparation of Financial Statements

These consolidated financial statements are prepared and reported in Canadian dollars in accordance with generally accepted accounting principles (GAAP) in Canada, which differ in some respects from GAAP in the United States. These differences are quantified and explained in note 20.

The consolidated financial statements include the accounts of Suncor Energy Inc. and its subsidiaries and the company's proportionate share of the assets, liabilities, equity, revenues, expenses and cash flows of its joint ventures. Subsidiaries are defined as entities in which the company holds a controlling interest, is the general partner or where it is subject to the majority of expected losses or gains.

The timely preparation of financial statements requires that management make estimates and assumptions, and use judgment regarding assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

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

(b) Cash Equivalents and Investments

Cash equivalents consist primarily of term deposits, certificates of deposit and all other highly liquid investments with a maturity at the time of purchase of three months or less. Investments with maturities greater than three months and up to one year are classified as short-term investments, while those with maturities in excess of one year are classified as long-term investments.

(c) Revenues

Crude oil sales from upstream operations (oil sands and natural gas) to downstream operations (refining and marketing) are based on actual product shipments. On consolidation, revenues and purchases related to these sales transactions are eliminated from operating revenues and purchases of crude oil and products.

The company also uses its natural gas production to offset purchases for internal consumption at its oil sands plant and Sarnia refinery. On consolidation, revenues from these sales are eliminated from operating revenues, crude oil and products purchases, and operating, selling and general expenses.

Revenues associated with sales of crude oil, natural gas, petroleum and petrochemical products and all other items not eliminated on consolidation are recorded when title passes to the customer and delivery has taken place. Revenues from oil and natural gas production from properties in which the company has an interest with other producers are recognized on the basis of the company's net working interest.

(d) Property, Plant and Equipment

Cost

Property, plant and equipment are recorded at cost.

Expenditures to acquire and develop oil sands mining properties are capitalized. Development costs to expand the capacity of existing mines or to develop mine areas substantially in advance of current production are also capitalized. Drilling and related seismic costs for regulatory approved mining areas are capitalized when planned future development timelines do not exceed 10 years. All other mining exploration costs are expensed as incurred.

The company follows the successful efforts method of accounting for its conventional natural gas and in-situ oil sands operations. Under the successful efforts method, acquisition costs of proved and unproved properties are capitalized. Costs of unproved properties are transferred to proved properties when proved reserves are confirmed. Exploration costs, including geological and geophysical costs, are expensed as incurred. Exploratory drilling costs are initially capitalized. If it is determined that a specific well does not contain proved reserves, the related capitalized exploratory drilling costs are charged to expense, as dry hole costs, at that time. Related land costs are expensed through the amortization of unproved properties as covered under the natural gas section of the depreciation, depletion and amortization policy below.

Development costs, which include the costs of wellhead equipment, development drilling costs, gas plants and handling facilities, applicable geological and geophysical costs and the costs of acquiring or constructing support facilities and equipment are capitalized. Costs incurred to operate and maintain wells and equipment and to lift oil and gas to the surface are expensed as operating costs.

Costs incurred after the inception of operations are expensed.

Interest Capitalization

Interest costs relating to major capital projects in progress and to the portion of non-producing oil and gas properties expected to become producing are capitalized as part of property, plant and equipment. Capitalization of interest ceases when the capital asset is substantially complete and ready for its intended productive use.

Leases

Leases that transfer substantially all the benefits and risks of ownership to the company are recorded as capital leases and classified as property, plant and equipment with offsetting long-term debt. All other leases are classified as operating leases under which leasing costs are expensed in the period incurred.

Depreciation, Depletion and Amortization

OIL SANDS Property, plant and equipment are depreciated over their useful lives on a straight-line basis, commencing when the assets are placed into service. Mine and mobile equipment is depreciated over periods ranging from three to 20 years and plant and other property and equipment, including leases in service, primarily over four to 40 years. Capitalized costs related to the in-progress phase of projects are not depreciated until the facilities are substantially complete and ready for their intended productive use.

NATURAL GAS Acquisition costs of unproved properties that are individually significant are evaluated for impairment by management. Impairment of unproved properties that are not individually significant is provided for through amortization over the average projected holding period for that portion of acquisition costs not expected to become producing. The average projected holding period of five years is based on historical experience.

Acquisition costs of proved properties are depleted using the unit of production method based on proved reserves. Capitalized exploratory drilling costs and development costs are depleted on the basis of proved developed reserves. For purposes of the depletion calculation, production and reserves volumes for oil and natural gas are converted to a common unit of measure on the basis of their approximate relative energy content. Gas plants, support facilities and equipment are depreciated on a straight-line basis over their useful lives, which average 12 years.

REFINING AND MARKETING Depreciation of property, plant and equipment is provided on a straight-line basis over the useful lives of assets. The Sarnia and Commerce City refineries and additions thereto are depreciated over an average of 30 years, service stations and related equipment over an average of 20 years and pipeline facilities and other equipment over three to 40 years.

Asset Retirement Obligations

A liability is recognized for future retirement obligations associated with the company's property, plant and equipment. The fair value of the Asset Retirement Obligation (ARO) is recorded on a discounted basis. This amount is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until the company settles the obligation.

Impairment

Property, plant and equipment are reviewed for impairment whenever events or conditions indicate that their net carrying amount, less future income taxes, may not be recoverable from estimated undiscounted future cash flows. If it is determined that the estimated net recoverable amount is less than the net carrying amount, a write-down to the asset's fair value is recognized during the period, with a charge to earnings.

Disposals

Gains or losses on disposals of non-oil and gas property, plant and equipment are recognized in earnings. For oil and gas property, plant and equipment, gains or losses are recognized in earnings for significant disposals or disposal of an entire property. However, the acquisition cost of a subsequently surrendered or abandoned unproved property that is not individually significant, or a partial abandonment of a proved property, is charged to accumulated depreciation, depletion and amortization.

(e) Deferred Charges and Other

The cost of major maintenance shutdowns is deferred and amortized on a straight-line basis over the period to the next shutdown, which varies from three to nine years. Normal maintenance and repair costs are charged to expense as incurred.

Deferred tax credits are government receivables, recognized when they are reasonably measurable and collectible, relating to eligible expenditures under various programs.

See also section (m) Recently Issued Accounting Standards.

(f) Employee Future Benefits

The company's employee future benefit programs consist of defined benefit and defined contribution pension plans, as well as other post-retirement benefits.

The estimated future cost of providing defined benefit pension and other post-retirement benefits is actuarially determined using management's best estimates of demographic and financial assumptions, and such cost is accrued proportionately from the date of hire of the employee to the date the employee becomes fully eligible to receive the benefits. The discount rate used to determine accrued benefit obligations is based on a year-end market rate of interest for high-quality debt instruments with cash flows that match the timing and amount of expected benefit payments. Company contributions to the defined contribution plan are expensed as incurred.

(g) Inventories

Inventories of crude oil and refined products are valued at the lower of cost (using the first-in, first-out (FIFO) method) and net realizable value.

Materials and supplies are valued at the lower of average cost and net realizable value.

Costs include direct and indirect expenditures incurred in bringing an item or product to its existing condition and location.

See also Note 1 – Changes in Accounting Policies.

(h) Financial Instruments

The company's financial instruments consist of cash and cash equivalents, accounts receivable, derivative contracts, substantially all current liabilities (except for the current portions of asset retirement and pension obligations, and future income taxes), and long-term debt.

The estimated fair values of financial instruments have been determined based on the company's assessment of available market information and appropriate valuation methodologies based on industry accepted third-party models; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction.

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

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

The company's fixed-term debt is accounted for under the amortized cost method with the exception of the portion of debt that has related financial hedges, which is accounted for under the fair value hedge methodology outlined above. Upon initial recognition, the cost of the debt is its fair value, adjusted for any associated transaction costs. We do not recognize gains or losses arising from changes in the fair value of this debt until the gains or losses are realized. Gains or losses on our U.S. dollar denominated long-term debt resulting from changes in the exchange rate are recognized in the period in which they occur.

See also Note 1 – Changes in Accounting Policies.

(i) Foreign Currency Translation

Monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars at rates of exchange in effect at the end of the period. The resulting exchange gains and losses are included in earnings. Other assets and related depreciation, depletion and amortization, other liabilities, revenues and expenses are translated at rates of exchange in effect at the respective transaction dates. The resulting exchange gains and losses are included in earnings.

United States operations of our refining and marketing business, and our corporate self-insurance operations are classified as self-sustaining and are translated into Canadian dollars using the current rate method. Assets and liabilities are translated at the period-end exchange rate, while revenues and expenses are translated using average exchange rates during the period. Translation gains or losses are included in other comprehensive income in the Consolidated Statements of Earnings and Comprehensive Income.

(j) Stock-Based Compensation Plans

Under the company's common share option programs (see note 12), common share options are granted to executives, employees and non-employee directors.

Compensation expense is recorded in the Consolidated Statements of Earnings and Comprehensive Income as operating, selling and general expense for all common share options granted to employees and non-employee directors on or after January 1, 2003, with a corresponding increase recorded as contributed surplus in the Consolidated Statements of Changes in Shareholders' Equity. The expense is based on the fair values of the option at the time of grant and is recognized in the Consolidated Statements of Earnings and Comprehensive Income over the estimated vesting periods of the respective options. For employees eligible to retire prior to the vesting date, the compensation expense is recognized over the shorter period. In instances where an employee is eligible to retire at the time of grant, the full expense is recognized immediately. Consideration paid to the company on exercise of options is credited to share capital.

For common share options granted prior to January 1, 2003 ("pre-2003 options"), compensation expense is not recognized in the Consolidated Statements of Earnings and Comprehensive Income. The company continues to disclose the pro forma earnings impact of related stock-based compensation expense for pre-2003 options.

Stock-based compensation awards that are to be settled in cash are measured using the fair value based method of accounting. The expense is based on the fair values of the award at the time of grant and the change in fair value from the time of grant. The expense is recognized in the Consolidated Statements of Earnings and Comprehensive Income over the estimated vesting periods of the respective award.

(k) Transportation Costs

Transportation costs billed to customers are classified as revenues with the related transportation costs classified as transportation and other costs in the Consolidated Statements of Earnings and Comprehensive Income.

(l) Income Taxes

Suncor follows the liability method of accounting for income taxes. Future income taxes are recorded for the effect of any difference between the accounting and income tax basis of an asset or liability, using enacted or substantively enacted income tax rates. Accumulated future income tax balances are adjusted to reflect changes in income tax rates that are substantively enacted with the adjustment being recognized in net earnings in the period that the change occurs. Investment tax credits are recorded as an offset to the related expenditures.

(m) Recently Issued Canadian Accounting Standards

Goodwill and Intangible Assets

In February 2008, the Canadian Institute of Chartered Accountants (CICA) approved Handbook section 3064 "Goodwill and Intangible Assets". Effective January 1, 2009, this new standard replaces section 3062 "Goodwill and Other Intangible Assets" and section 3450 "Research and Development Costs". The standard focuses on the criteria for asset recognition in the financial statements, including those internally developed. The new standard will not materially impact net earnings or financial position, however will result in the reclassification and presentation of certain balances on the balance sheet. At December 31, 2008, $566 million of turnaround costs would have been reclassified as part of Property, Plant and equipment (December 31, 2007 – $296 million).

International Financial Reporting Standards

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

The company's IFRS conversion project began in 2008. A formal project plan, governance structure, and a project team, including an external advisor, have been established. The project philosophy is to align with current accounting practices and policies, where possible, to minimize the impact of any changes to the business. Regular reporting is provided to senior management and the Audit Committee of the Board of Directors. Specific changes resulting from implementation of IFRS have not been determined at this time.

CONSOLIDATED STATEMENTS OF EARNINGS AND COMPREHENSIVE INCOME

For the years ended December 31 ($ millions)	2008	2007 (restated) (note 1)	2006 (restated) (note 1)
Revenues			
Operating revenues (notes 7, 17 and 19)	**18 336**	15 020	13 798
Energy marketing and trading activities (note 7d)	**11 725**	3 515	2 299
Net insurance proceeds	**—**	—	436
Interest	**28**	30	13
	30 089	18 565	16 546
Expenses			
Purchases of crude oil and products	**7 184**	5 817	4 670
Operating, selling and general	**4 044**	3 340	3 066
Energy marketing and trading activities (note 7d)	**11 717**	3 467	2 261
Transportation and other costs	**275**	182	203
Depreciation, depletion and amortization	**1 049**	864	695
Accretion of asset retirement obligations	**64**	48	34
Exploration (note 19)	**90**	95	104
Royalties (note 5)	**890**	691	1 038
Taxes other than income taxes (note 19)	**679**	648	595
Loss (gain) on disposal of assets	**13**	7	(1)
Project start-up costs	**35**	68	45
Financing expenses (income) (note 15)	**917**	(211)	39
	26 957	15 016	12 749
Earnings Before Income Taxes	**3 132**	3 549	3 797
Provision for income taxes (note 11)			
Current	**514**	382	20
Future	**481**	184	808
	995	566	828
Net Earnings	**2 137**	2 983	2 969
Other comprehensive income (loss) (notes 7 and 18)	**350**	(190)	10
Comprehensive Income	**2 487**	2 793	2 979
Net Earnings Per Common Share (dollars) (note 14)			
Net earnings attributable to common shareholders			
Basic	**2.29**	3.23	3.23
Diluted	**2.26**	3.17	3.16
Cash dividends	**0.20**	0.19	0.15

See accompanying Summary of Significant Accounting Policies and Notes.

CONSOLIDATED BALANCE SHEETS

As at December 31 ($ millions)	2008	2007 (restated) (note 1)
Assets		
Current assets		
Cash and cash equivalents	**660**	569
Accounts receivable (notes 7, 12 and 19)	**1 580**	1 438
Inventories (notes 1 and 16)	**909**	1 012
Income taxes receivable	**67**	95
Future income taxes (note 11)	**21**	46
Total current assets	**3 237**	3 160
Property, plant and equipment, net (note 3)	**28 316**	20 945
Deferred charges and other (note 4)	**975**	404
Total assets	**32 528**	24 509
Liabilities and Shareholders' Equity		
Current liabilities		
Short-term debt	**11**	6
Accounts payable and accrued liabilities (notes 7, 9, 10 and 13)	**3 229**	2 797
Taxes other than income taxes	**97**	72
Income taxes payable	**81**	244
Future income taxes	**111**	37
Total current liabilities	**3 529**	3 156
Long-term debt (note 6)	**7 875**	3 811
Accrued liabilities and other (notes 7, 9, 10 and 13)	**1 986**	1 434
Future income taxes (note 11)	**4 615**	4 212
Total liabilities	**18 005**	12 613
Commitments and contingencies (note 12)		
Shareholders' equity		
Share capital (note 13)	**1 113**	881
Contributed surplus (note 13)	**288**	194
Accumulated other comprehensive income (loss) (notes 7 and 18)	**97**	(253)
Retained earnings (note 1)	**13 025**	11 074
Total shareholders' equity	**14 523**	11 896
Total liabilities and shareholders' equity	**32 528**	24 509

See accompanying Summary of Significant Accounting Policies and Notes.

Approved on behalf of the Board of Directors:

Richard L. George
Director

Brian A. Canfield
Director

February 25, 2009

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31 ($ millions)	**2008**	2007 (restated) (note 1)	2006 (restated) (note 1)
Operating Activities			
Cash flow from operations [a]	**4 463**	4 009	4 524
Decrease (increase) in operating working capital			
Accounts receivable	**(134)**	(387)	53
Inventories	**103**	(223)	(57)
Accounts payable and accrued liabilities	**140**	248	87
Taxes payable/receivable	**(110)**	246	(43)
Cash flow from operating activities	**4 462**	3 893	4 564
Cash Used in Investing Activities [a]	**(7 590)**	(5 362)	(3 489)
Net Cash (Deficiency) Surplus Before Financing Activities	**(3 128)**	(1 469)	1 075
Financing Activities			
Decrease in short-term debt	**(1)**	(4)	(42)
Proceeds from issuance of long-term debt	**2 704**	1 835	—
Net increase (decrease) in long-term debt	**422**	(171)	(622)
Issuance of common shares under stock option plans	**190**	62	45
Dividends paid on common shares	**(180)**	(162)	(127)
Deferred revenue	**—**	4	27
Cash flow provided by (used in) financing activities	**3 135**	1 564	(719)
Increase in Cash and Cash Equivalents	**7**	95	356
Effect of Foreign Exchange on Cash and Cash Equivalents	**84**	(47)	—
Cash and Cash Equivalents at Beginning of Year	**569**	521	165
Cash and Cash Equivalents at End of Year	**660**	569	521

(a) See Schedules of Segmented Data on pages 58 and 59.

See accompanying Summary of Significant Accounting Policies and Notes.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

For the years ended December 31 ($ millions)	Share Capital	Contributed Surplus	Accumulated Other Comprehensive Income (AOCI)	Retained Earnings
At December 31, 2005, as previously reported	732	50	(81)	5 295
Retroactive adjustment for change in accounting policy, net of tax (note 1)	—	—	—	134
At December 31, 2005, as restated	732	50	(81)	5 429
Net earnings	—	—	—	2 969
Dividends paid on common shares	—	—	—	(127)
Issued for cash under stock option plans	52	(7)	—	—
Issued under dividend reinvestment plan	10	—	—	(10)
Stock-based compensation expense	—	53	—	—
Income tax benefit of stock option deductions in the U.S.	—	4	—	—
Change in AOCI related to foreign currency translation	—	—	10	—
At December 31, 2006, as restated	794	100	(71)	8 261
Net earnings	—	—	—	2 983
Dividends paid on common shares	—	—	—	(162)
Issued for cash under stock option plans	74	(12)	—	—
Issued under dividend reinvestment plan	13	—	—	(13)
Stock-based compensation expense	—	103	—	—
Income tax benefit of stock option deductions in the U.S.	—	3	—	—
Adjustment to opening retained earnings arising from ineffective portion of cash flow hedges at January 1, 2007	—	—	—	5
Adjustment to opening AOCI arising from effective portion of cash flow hedges at January 1, 2007	—	—	8	—
Change in AOCI related to foreign currency translation	—	—	(195)	—
Change in AOCI related to derivative hedging activities	—	—	5	—
At December 31, 2007, as restated	881	194	(253)	11 074
Net earnings	**—**	**—**	**—**	**2 137**
Dividends paid on common shares	**—**	**—**	**—**	**(180)**
Issued for cash under stock option plans	**226**	**(36)**	**—**	**—**
Issued under dividend reinvestment plan	**6**	**—**	**—**	**(6)**
Stock-based compensation expense	**—**	**120**	**—**	**—**
Income tax benefit of stock option deductions in the U.S.	**—**	**10**	**—**	**—**
Change in AOCI related to foreign currency translation	**—**	**—**	**350**	**—**
Change in AOCI related to derivative hedging activities	**—**	**—**	**—**	**—**
At December 31, 2008	**1 113**	**288**	**97**	**13 025**

See accompanying Summary of Significant Accounting Policies and Notes.

SCHEDULES OF SEGMENTED DATA [(a)]

For the years ended December 31 ($ millions)	Oil Sands			Natural Gas			Refining and Marketing (note 2)		
	2008	2007	2006	**2008**	2007	2006	**2008**	2007	2006
EARNINGS									
Revenues [(b)]									
Operating revenues	**8 077**	6 195	6 259	**696**	541	554	**9 543**	8 278	6 981
Energy marketing and trading activities	**—**	—	—	**—**	—	—	**11 827**	3 522	2 324
Net insurance proceeds	**—**	—	436	**—**	—	—	**—**	—	—
Intersegment revenues [(c)]	**1 309**	580	712	**58**	12	23	**—**	—	—
Interest	**—**	—	—	**—**	—	1	**1**	5	5
	9 386	6 775	7 407	**754**	553	578	**21 371**	11 805	9 310
Expenses									
Purchases of crude oil and products	**574**	157	89	**—**	—	—	**8 074**	6 250	5 297
Operating, selling and general (note 2)	**3 124**	2 384	2 212	**155**	151	119	**715**	693	669
Energy marketing and trading activities	**—**	—	—	**—**	—	—	**11 725**	3 473	2 292
Transportation and other costs	**229**	138	162	**17**	15	16	**29**	29	25
Depreciation, depletion and amortization	**580**	462	385	**225**	189	152	**202**	171	132
Accretion of asset retirement obligations	**55**	40	28	**8**	7	5	**1**	1	1
Exploration	**17**	13	22	**73**	82	82	**—**	—	—
Royalties (note 5)	**715**	565	911	**175**	126	127	**—**	—	—
Taxes other than income taxes	**111**	90	75	**5**	4	3	**562**	553	516
Loss (gain) on disposal of assets	**36**	1	—	**(22)**	(1)	(4)	**6**	7	3
Project start-up costs	**35**	60	38	**—**	—	—	**—**	8	7
Financing expenses (income)	**—**	—	—	**—**	—	—	**—**	—	—
	5 476	3 910	3 922	**636**	573	500	**21 314**	11 185	8 942
Earnings (loss) before income taxes	**3 910**	2 865	3 485	**118**	(20)	78	**57**	620	368
Income taxes	**(1 035)**	(391)	(710)	**(29)**	45	28	**(6)**	(176)	(124)
Net earnings (loss)	**2 875**	2 474	2 775	**89**	25	106	**51**	444	244
As at December 31									
TOTAL ASSETS	**25 795**	18 172	13 727	**1 862**	1 811	1 503	**4 666**	4 825	4 219

(a) Accounting policies for segments are the same as those described in the Summary of Significant Accounting Policies.
(b) There were no customers that represented 10% or more of the company's 2008, 2007 or 2006 consolidated revenues.
(c) Intersegment revenues are recorded at prevailing fair market prices and accounted for as if the sales were to third parties.

See accompanying Summary of Significant Accounting Policies and Notes.

SCHEDULES OF SEGMENTED DATA[a] (continued)

For the years ended December 31 ($ millions)	Corporate and Eliminations 2008	2007	2006	Total 2008	2007	2006
EARNINGS						
Revenues[b]						
Operating revenues	**20**	6	4	**18 336**	15 020	13 798
Energy marketing and trading activities	**(102)**	(7)	(25)	**11 725**	3 515	2 299
Net insurance proceeds	**—**	—	—	**—**	—	436
Intersegment revenues[c]	**(1 367)**	(592)	(735)	**—**	—	—
Interest	**27**	25	7	**28**	30	13
	(1 422)	(568)	(749)	**30 089**	18 565	16 546
Expenses						
Purchases of crude oil and products	**(1 464)**	(590)	(716)	**7 184**	5 817	4 670
Operating, selling and general (note 2)	**50**	112	66	**4 044**	3 340	3 066
Energy marketing and trading activities	**(8)**	(6)	(31)	**11 717**	3 467	2 261
Transportation and other costs	**—**	—	—	**275**	182	203
Depreciation, depletion and amortization	**42**	42	26	**1 049**	864	695
Accretion of asset retirement obligations	**—**	—	—	**64**	48	34
Exploration	**—**	—	—	**90**	95	104
Royalties (note 5)	**—**	—	—	**890**	691	1 038
Taxes other than income taxes	**1**	1	1	**679**	648	595
Loss (gain) on disposal of assets	**(7)**	—	—	**13**	7	(1)
Project start-up costs	**—**	—	—	**35**	68	45
Financing expenses (income)	**917**	(211)	39	**917**	(211)	39
	(469)	(652)	(615)	**26 957**	15 016	12 749
Earnings (loss) before income taxes	**(953)**	84	(134)	**3 132**	3 549	3 797
Income taxes	**75**	(44)	(22)	**(995)**	(566)	(828)
Net earnings (loss)	**(878)**	40	(156)	**2 137**	2 983	2 969
As at December 31						
TOTAL ASSETS	**205**	(299)	(490)	**32 528**	24 509	18 959

SCHEDULES OF SEGMENTED DATA[a] (continued)

For the years ended December 31 ($ millions)	Oil Sands			Natural Gas			Refining and Marketing (note 2)		
	2008	2007	2006	**2008**	2007	2006	**2008**	2007	2006
CASH FLOW BEFORE FINANCING ACTIVITIES									
Cash from (used in) operating activities:									
Cash flow from (used in) operations									
Net earnings (loss)	**2 875**	2 474	2 775	**89**	25	106	**51**	444	244
Exploration expenses	**—**	—	—	**61**	67	52	**—**	—	—
Non-cash items included in earnings									
Depreciation, depletion and amortization	**580**	462	385	**225**	189	152	**202**	171	132
Future income taxes	**535**	108	725	**15**	(43)	(28)	**(7)**	77	69
Loss (gain) on disposal of assets	**36**	1	—	**(22)**	(1)	(4)	**6**	7	3
Stock-based compensation expense	**60**	49	25	**4**	5	2	**19**	25	13
Other	**(54)**	1	14	**(4)**	7	1	**2**	(5)	(7)
Increase (decrease) in deferred credits and other	**(194)**	48	(21)	**—**	(1)	—	**5**	(3)	(3)
Total cash flow from (used in) operations	**3 838**	3 143	3 903	**368**	248	281	**278**	716	451
Decrease (increase) in operating working capital	**603**	586	440	**42**	22	(27)	**(30)**	(254)	(110)
Total cash from (used in) operating activities	**4 441**	3 729	4 343	**410**	270	254	**248**	462	341
Cash from (used in) investing activities:									
Capital and exploration expenditures	**(7 051)**	(4 431)	(2 463)	**(339)**	(531)	(458)	**(172)**	(376)	(665)
Deferred maintenance shutdown expenditures	**(340)**	(135)	—	**(3)**	(6)	—	**(54)**	(73)	(80)
Deferred outlays and other investments	**(39)**	(18)	(2)	**—**	—	—	**(11)**	—	7
Proceeds from disposals	**—**	3	2	**26**	5	15	**—**	1	4
Proceeds from property loss	**—**	—	36	**—**	—	—	**—**	—	—
Decrease (increase) in investing working capital	**434**	333	197	**—**	—	—	**(19)**	(43)	(53)
Total cash (used in) investing activities	**(6 996)**	(4 248)	(2 230)	**(316)**	(532)	(443)	**(256)**	(491)	(787)
Net cash surplus (deficiency) before financing activities	**(2 555)**	(519)	2 113	**94**	(262)	(189)	**(8)**	(29)	(446)

(a) Accounting policies for segments are the same as those described in the Summary of Significant Accounting Policies.

See accompanying Summary of Significant Accounting Policies and Notes.

SCHEDULES OF SEGMENTED DATA[a] (continued)

For the years ended December 31 ($ millions)	Corporate and Eliminations			Total		
	2008	2007	2006	**2008**	2007	2006
CASH FLOW BEFORE FINANCING ACTIVITIES						
Cash from (used in) operating activities:						
Cash flow from (used in) operations						
Net earnings (loss)	**(878)**	40	(156)	**2 137**	2 983	2 969
Exploration expenses	**—**	—	—	**61**	67	52
Non-cash items included in earnings						
Depreciation, depletion and amortization	**42**	42	26	**1 049**	864	695
Future income taxes	**(62)**	42	42	**481**	184	808
Loss (gain) on disposal of assets	**(7)**	—	—	**13**	7	(1)
Stock-based compensation expense	**37**	24	13	**120**	103	53
Other	**824**	(236)	(22)	**768**	(233)	(14)
Increase (decrease) in deferred credits and other	**23**	(10)	(14)	**(166)**	34	(38)
Total cash flow from (used in) operations	**(21)**	(98)	(111)	**4 463**	4 009	4 524
Decrease (increase) in operating working capital	**(616)**	(470)	(263)	**(1)**	(116)	40
Total cash from (used in) operating activities	**(637)**	(568)	(374)	**4 462**	3 893	4 564
Cash from (used in) investing activities:						
Capital and exploration expenditures	**(28)**	(77)	(27)	**(7 590)**	(5 415)	(3 613)
Deferred maintenance shutdown expenditures	**—**	—	—	**(397)**	(214)	(80)
Deferred outlays and other investments	**(1)**	(14)	(2)	**(51)**	(32)	3
Proceeds from disposals	**7**	—	—	**33**	9	21
Proceeds from property loss	**—**	—	—	**—**	—	36
Decrease (increase) in investing working capital	**—**	—	—	**415**	290	144
Total cash (used in) investing activities	**(22)**	(91)	(29)	**(7 590)**	(5 362)	(3 489)
Net cash surplus (deficiency) before financing activities	**(659)**	(659)	(403)	**(3 128)**	(1 469)	1 075

SUNCOR ENERGY INC.
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. CHANGES IN ACCOUNTING POLICIES

(a) Inventories

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

Change in Consolidated Balance Sheets

($ millions, increase/(decrease))	**As at December 31 2008**	As at December 31 2007
Inventories	**110**	404
Total assets	**110**	404
Future income taxes	**30**	121
Retained earnings	**80**	283
Total liabilities and shareholders' equity	**110**	404

Change in Consolidated Statements of Earnings (Loss) and Comprehensive Income

	Twelve months ended December 31		
($ millions, increase/(decrease))	**2008**	2007	2006
Purchases of crude oil and products	**270**	(153)	(5)
Operating, selling and general	**24**	(51)	14
Future income taxes	**(91)**	53	(7)
Net earnings (loss)	**(203)**	151	(2)
Per common share – basic (dollars)	**(0.22)**	0.16	—
Per common share – diluted (dollars)	**(0.22)**	0.16	—

(b) Capital Disclosure

On January 1, 2008, the company adopted CICA Handbook section 1535 "Capital Disclosures". This section establishes disclosure requirements for management's policies and processes in defining and managing its capital. There was no financial impact to previously reported financial statements as a result of the implementation of this new standard. See note 8 for disclosure of the new section.

(c) Financial Instruments – Disclosures and Presentation

On January 1, 2008, the company adopted CICA Handbook sections 3862 "Financial Instruments – Disclosures" and 3863 "Financial Instruments – Presentation", which enhance existing disclosures for financial instruments. In particular, section 3862 focuses on the identification of risk exposures and the company's approach to management of these risks. There was no financial impact to previously reported financial statements as a result of the implementation of this new standard. See note 7 for disclosure of new sections.

2. CHANGE IN SEGMENTED DISCLOSURES

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

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

3. PROPERTY, PLANT AND EQUIPMENT

	2008		2007	
($ millions)	Cost	Accumulated Provision	Cost	Accumulated Provision
Oil sands				
Plant	**15 229**	**2 282**	11 049	1 962
Mine and mobile equipment	**1 777**	**469**	1 423	388
In-situ properties	**2 881**	**301**	2 566	222
Pipeline	**149**	**40**	149	35
Capital leases	**102**	**10**	102	6
Major projects in progress (1)	**6 582**	**—**	3 830	—
	26 720	**3 102**	19 119	2 613
Natural gas				
Proved properties	**2 542**	**1 239**	2 213	1 042
Unproved properties	**146**	**30**	139	32
Other support facilities and equipment	**102**	**38**	92	30
Wells in progress	**211**	**—**	291	—
	3 001	**1 307**	2 735	1 104
Refining and marketing				
Refinery	**2 973**	**754**	2 699	628
Marketing	**844**	**330**	783	304
Pipeline	**87**	**7**	53	4
	3 904	**1 091**	3 535	936
Corporate	**329**	**138**	305	96
	33 954	**5 638**	25 694	4 749
Net property, plant and equipment		**28 316**		20 945

(1) This balance only includes certain major projects in progress. Total assets under construction not being depreciated at December 31, 2008 is $11.1 billion (2007 – $6.3 billion).

4. DEFERRED CHARGES AND OTHER

($ millions)	**2008**	2007
Deferred maintenance shutdown costs	**566**	296
Deferred government tax credits	**35**	36
Unrealized mark to market gains	**273**	6
Other	**101**	66
Total deferred charges and other	**975**	404

5. ROYALTIES

The company's current estimation of Alberta Crown royalties is based on regulations that were in effect until the end of 2008. Alberta Crown royalties for each oil sands project require payments to the Government of Alberta based on annual gross revenues less related allowable 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. Royalty expense for the company's oil sands operations for the year ended December 31, 2008, was $715 million (2007 – $565 million, 2006 – $911 million). The balance of the consolidated royalty expense is in respect of natural gas royalties of $175 million (2007 – $126 million, 2006 – $127 million).

The New Royalty Framework changes enacted by the Government of Alberta will increase royalty rates, effective January 1, 2009 to a sliding scale of 25% – 40% of R-C, subject to a minimum royalty of 1%-9% depending on oil price. In both cases, the sliding scale royalty would move with increases in WTI prices from the minimum rates at Cdn $55 to the maximum rates at a WTI price of Cdn $120.

The New Royalty Framework changes and the new sliding scale royalty rates outlined above apply to our Firebag in-situ project effective January 1, 2009.

In January 2008, the company entered into a Royalty Amending Agreement with the government of Alberta to transition our base oil sands mining operations to the New Royalty Framework rates in the New Royalty Framework. Commencing January 1, 2010 until December 31, 2015, the new royalty rates will apply to the bitumen royalty for current production levels, subject to a cap of 30% of R-C, and a minimum royalty of 1% to 1.2% of R. In addition, the Suncor Royalty Amending Agreement provides the company with a level of certainty for various matters, including the bitumen valuation methodology, allowed costs, royalty in-kind, and certain taxes. In 2016 and subsequent years, the limitations on royalty rates and other matters will no longer apply and our base mine operations will be subject to royalty under the terms of the New Royalty Framework, unless it is amended or superseded prior to that time.

6. LONG-TERM DEBT

A. Fixed-term debt, redeemable at the option of the company

($ millions)	**2008**	2007
6.85% Notes, denominated in U.S. dollars, due in 2039 (US$750)(i)	**918**	—
6.50% Notes, denominated in U.S. dollars, due in 2038 (US$1150)(iii)	**1 408**	1 137
5.95% Notes, denominated in U.S. dollars, due in 2034 (US$500)	**612**	494
7.15% Notes, denominated in U.S. dollars, due in 2032 (US$500)	**612**	494
6.10% Notes, denominated in U.S. dollars, due in 2018 (US$1250)(i)	**1 531**	—
5.39% Series 4 Medium Term Notes, due in 2037(iv)	**600**	600
5.80% Series 4 Medium Term Notes, due in 2018(ii)	**700**	—
6.70% Series 2 Medium Term Notes, due in 2011(v)	**500**	500
	6 881	3 225
Revolving-term debt, with interest at variable rates (see B. Credit facilities)		
Commercial Paper (interest at December 31, 2008 – 2.2%, 2007 – 4.8%)(vi)	**934**	522
Total unsecured long-term debt	**7 815**	3 747
Secured long-term debt	**13**	1
Capital leases(vii), (viii)	**103**	102
Fair values of interest swaps	**16**	6
Deferred financing costs	**(72)**	(45)
Total long-term debt	**7 875**	3 811

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

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

(iii) During the third quarter of 2007, the company issued additional 6.50% Notes with a principal amount of US$400 million under an outstanding US$2 billion debt shelf prospectus. These notes bear interest, which is paid semi-annually, and mature on June 15, 2038. The net proceeds were used for general corporate purposes, including reducing short-term borrowings, supporting our ongoing capital spending program and for working capital requirements.

During the second quarter of 2007, the company issued 6.50% Notes with a principal amount of US$750 million under an outstanding US$2 billion debt shelf prospectus. These notes bear interest, which is paid semi-annually, and mature on June 15, 2038. The net proceeds were used for general corporate purposes, including reducing short-term borrowings, supporting our ongoing capital spending program and for working capital requirements.

(iv) During the first quarter of 2007, the company issued 5.39% Medium Term Notes with a principal amount of $600 million under an outstanding $2 billion debt shelf prospectus. These notes bear interest, which is paid semi-annually, and mature on March 26, 2037. The net proceeds were used for general corporate purposes, including reducing short-term borrowings, supporting our ongoing capital spending program and for working capital requirements.

(v) The company has entered into interest rate swap transactions. The swap transactions result in an average effective interest rate that is different from the stated interest rate of the related underlying long-term debt instruments.

Description of Swap Transaction	Principal Swapped ($ millions)	Swap Maturity	Effective Interest Rate 2008	Effective Interest Rate 2007
Swap of 6.70% Medium Term Notes to floating rates	200	2011	4.8%	5.7%

(vi) The company is authorized to issue commercial paper to a maximum of $1,500 million having a term not to exceed 365 days. Commercial paper is supported by unutilized credit facilities (see B. Credit facilities).

(vii) Equipment leases with interest rates between 6.5% and 13.4% and maturity dates ranging from 2009 to 2037.

(viii) Future minimum amounts payable under capital leases and other long-term debt are as follows:

($ millions)	Capital Leases	Other Long-term Debt
2009	9	963 [(a)]
2010	9	—
2011	10	500
2012	10	—
2013	9	—
Later years	265	6 309
Total minimum payments	312	7 772
Less amount representing imputed interest	209	
Present value of obligation under capital leases	103	

(a) Long-term debt due in the next year will be refinanced with available credit facilities

Long-term Debt (per cent)

	2008	2007
Variable rate	**15**	19
Fixed rate	**85**	81

B. Credit facilities

During 2008, the company's $330 million bilateral credit facility was amended and extended by one year to 2009 and the credit limit was increased by $150 million to $480 million total funds available. The company's $2 billion syndicated credit facility was renegotiated and extended by one year to have a five year term expiring in March 2013 and the credit limit was increased to $3.75 billion. Additionally, an $8 million demand credit facility was negotiated. At December 31, 2008, the company had available credit facilities of $4,283 million, of which $3,030 million was undrawn as follows:

($ millions)	**2008**
Facility that is fully revolving for 364 days, has a term period of one year and expires in 2009	480
Facility that is fully revolving for a period of five years and expires in 2013	3 750
Facilities that can be terminated at any time at the option of the lenders	53
Total available credit facilities	4 283
Credit facilities supporting outstanding commercial paper	934
Credit facilities supporting standby letters of credit	319
Total undrawn credit facilities	3 030

7. FINANCIAL INSTRUMENTS AND FINANCIAL RISK FACTORS

Derivatives are financial instruments that either imitate or counter the price movements of stocks, bonds, currencies, commodities and interest rates. Suncor uses derivatives to reduce (hedge) its exposure to fluctuations in commodity prices and foreign currency exchange rates and to manage interest rate or currency-sensitive assets and liabilities. Suncor also uses derivatives for trading purposes. When used in a trading activity, the company is attempting to realize a gain on the fluctuations in the market value of the derivative.

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

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

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

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

Hedge accounting is a method for recognizing the gains, losses, revenues and expenses associated with the items in a hedging relationship at the time when the underlying transaction impacts earnings. Suncor has elected to use hedge accounting on certain derivatives linked to future commodity and financial transactions.

See below for more technical details and amounts.

Financial Instruments

(a) Balance Sheet Financial Instruments

The company's financial instruments in the Consolidated Balance Sheets consist of cash and cash equivalents, accounts receivable, derivative contracts, substantially all current liabilities (except for the current portions of asset retirement and pension obligations and future income taxes), and long-term debt. Unless otherwise noted, carrying values reflect the current fair value of the company's financial instruments.

The estimated fair values of recognized financial instruments have been determined based on the company's assessment of available market information and appropriate valuation methodologies based on industry accepted third-party models; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction.

The company's fixed-term debt is accounted for under the amortized cost method. Upon initial recognition, the cost of the debt is its fair value, adjusted for any associated transaction costs. We do not recognize gains or losses arising from changes in the fair value of this debt until the gains or losses are realized. Gains or losses on our U.S. dollar denominated long-term debt resulting from changes in the exchange rate are recognized in the period in which they occur. At December 31, 2008, the carrying value of our fixed-term debt accounted for under the amortized cost method was $6.7 billion (December 31, 2007 – $3.0 billion) and the fair value at December 31, 2008 was $5.4 billion (December 31, 2007 – $3.1 billion).

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

Fair Value Hedges

The company periodically enters into derivative financial instrument contracts such as interest rate swaps as part of its risk management strategy to manage its exposure to benchmark interest rate fluctuations. The interest rate swap contracts involve an exchange of floating rate versus fixed rate interest payments between the company and investment grade counterparties. The differentials on the exchange of periodic interest payments are recognized in earnings as an adjustment to interest expense. The fair value of the underlying debt is adjusted by the fair value change in the derivative financial instrument with the offset to interest expense. At December 31, 2008, the company had interest rate swaps classified as fair value hedges outstanding for up to three years relating to fixed-rate debt. There was no ineffectiveness recognized on interest rate swaps designated as fair value hedges during the twelve month period ended December 31, 2008 (no ineffectiveness during the twelve month period ended December 31, 2007). The fair value of interest rate swap contracts outstanding at December 31, 2008 is detailed in note 6, Long-term debt.

The company periodically enters into derivative contracts to hedge risks specific to individual transactions. The differentials between the fair value of the hedged transactions and the fair value of the derivative contracts are recognized in earnings as an adjustment to operating revenues. The earnings impact associated with hedge ineffectiveness on derivative contracts to hedge risks specific to individual transactions during the twelve month period ended December 31, 2008 was a loss of $4 million, net of income taxes of $2 million (2007 – gain of $4 million, net of income taxes of $2 million).

Cash Flow Hedges

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

At December 31, 2008, the company had hedged a portion of its forecasted cash flows subject to natural gas price risk for the first quarter of 2009 related to our refinery natural gas consumption.

There was no earnings impact associated with realized and unrealized hedge ineffectiveness on derivative contracts designated as cash flow hedges during the twelve month period ended December 31, 2008 (2007 – loss of $5 million, net of income taxes of $2 million).

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

Contracts outstanding at December 31, were as follows:

Revenue Hedges

Strategic Crude Oil	Quantity (bpd)	Average Price (US$/bbl) [a]	Revenue Hedged (Cdn$ millions) [b]	Hedge Period [c]
As at December 31, 2008	**—**	**—**	**—**	**—**
As at December 31, 2007				
Costless collars	10 000	59.85 – 101.06	216 – 365	2008
As at December 31, 2006				
Costless collars	60 000	51.64 – 93.26	1 318 – 2 380	2007
Costless collars	10 000	59.85 – 101.06	255 – 431	2008

Natural Gas	Quantity (GJ/day)	Average Price (Cdn$/GJ)	Revenue Hedged (Cdn$ millions)	Hedge Period [c]
As at December 31, 2008	**—**	**—**	**—**	**—**
As at December 31, 2007	—	—	—	—
As at December 31, 2006				
Swaps	4 000	6.11	9	2007

Consumption Hedges	Quantity (MMBtu/day)	Average Price (US$/MMBtu)	Consumption Hedged (Cdn$ millions) [b]	Hedge Period [c]
As at December 31, 2008				
Natural Gas – fixed price purchases	**25 000**	**6.92**	**19**	**2009** [d]
As at December 31, 2007	—	—	—	—
As at December 31, 2006	—	—	—	—

Foreign Currency Hedges	Notional (Euro Millions)	Average Forward Rate	Dollars Hedged (Cdn$ millions)	Hedge Period [c]
As at December 31, 2008	—	—	—	—
As at December 31, 2007	—	—	—	—
As at December 31, 2006				
Euro/Cdn forward	20.6	1.41	29.0	2007 [e]

(a) Average price for crude costless collars is US$ WTI per barrel at Cushing, Oklahoma.
(b) The revenue and consumption hedged is translated to Cdn$ at the respective year-end exchange rate for convenience purposes.
(c) Original hedge term is for the full year unless otherwise noted.
(d) For the period January to March 2009, inclusive.
(e) Settlement for applicable forwards occurring within the period April to September 2007.

Fair Value of Hedging Derivative Financial Instruments

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

($ millions)	**December 31 2008**	December 31 2007
Revenue and consumption hedges	**(2)**	(11)
Fixed to floating interest rate swaps	**24**	8
Specific hedges of individual transactions	**(11)**	12
Fair value of outstanding hedging derivative financial instruments	**11**	9

Accumulated Other Comprehensive Income (AOCI)

A reconciliation of changes in AOCI attributable to derivative hedging activities for the twelve month period ending December 31 is as follows:

($ millions)	**2008**	2007
AOCI attributable to derivative hedging activities, beginning of the period, net of income taxes of $4 (2007 – $5)	**13**	8
Current year net changes arising from cash flow hedges, net of income taxes of $2 (2007 – $1)	**(7)**	8
Net unrealized hedging losses (gains) at the beginning of the year reclassified to earnings during the period, net of income taxes of $3 (2007 – $2)	**7**	(3)
AOCI attributable to derivative hedging activities, at December 31, net of income taxes of $5 (2007 – $4)	**13**	13

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

The company also periodically enters into derivative financial instruments such as options, basis swaps, and heat rate swaps that either do not qualify for hedge accounting treatment or hedges that the company has not elected to document as part of a qualifying hedge relationship. These financial instruments are accounted for using the mark-to-market method and, as such, these derivative instruments are recorded at fair value at each balance sheet date. The earnings impact associated with these contracts for the twelve month period ended December 31, 2008, was a gain of $348 million, net of income taxes of $142 million (2007 – a loss of $3 million, net of income taxes of $1 million).

Significant contracts outstanding at December 31, 2008 were as follows:

Crude Oil [d]	Quantity (bpd)	Price (US$/bbl) [a]	Revenue Hedged (Cdn$ millions) [b]	Hedge Period [c]
Purchased puts	**55 000**	**60.00**	**1 475**	**2009**
Purchased puts	**55 000**	**60.00**	**1 475**	**2010**

(a) Price for crude puts is US$ WTI per barrel at Cushing, Oklahoma.
(b) The revenue hedged is translated to Cdn$ at the December 31, 2008 exchange rate for convenience purposes.
(c) Original hedge term is for the full year.
(d) Premiums paid was US$59 million.

For information on significant contracts entered into subsequent to December 31, 2008, see page 77.

(d) Energy Marketing and Trading Activities

In addition to the financial derivatives used for hedging activities, the company uses physical and financial energy contracts, including swaps, forwards and options to earn trading and marketing revenues. These energy contracts are comprised of crude oil, natural gas and refined products contracts. Financial energy trading activities are accounted for using the mark-to-market method. Physical energy marketing contracts involve activities intended to enhance prices and satisfy physical deliveries to customers. The results of these activities are reported as revenue and as energy marketing and trading expenses in the

Consolidated Statements of Earnings and Comprehensive Income. Net pretax earnings (loss) for the twelve month period ended December 31 for our energy and trading activities in our refining and marketing segment were as follows:

Net Pretax Earnings (Loss)

($ millions)	**2008**	2007	2006
Physical energy contracts trading activity	**100**	57	38
Financial energy contracts trading activity	**7**	(4)	(3)
General and administrative costs	**(5)**	(4)	(3)
Total	**102**	49	32

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

The fair value of unsettled (unrealized) energy derivative assets and liabilities, which includes all financial contracts referenced in section (c) & (d) above are as follows:

($ millions)	**December 31 2008**	December 31 2007
Energy trading assets[(a)]	**635**	18
Energy trading liabilities[(b)]	**14**	21
Net energy trading assets (liabilities)	**621**	(3)

(a) As at December 31, 2008, $376 million is recorded in accounts receivable (2007 – $18 million) and $259 million is recorded in deferred charges and other (2007 – nil) in the Consolidated Balance Sheets.

(b) As at December 31, 2008, $14 million is recorded in accrued liabilities and other (2007 – $21 million) in the Consolidated Balance Sheets.

Change in fair value of net assets

($ millions)	**2008**
Fair value of contracts at December 31, 2007	**(3)**
Fair value of contracts realized during the period	**(53)**
Fair value of contracts entered into during the period	**673**
Changes in fair value during the period	**4**
Fair value of contracts outstanding at December 31, 2008	**621**

Financial Risk Factors

The company is exposed to a number of different financial risks arising from normal course business exposures, as well as the company's use of financial instruments. These risk factors include market risks relating to commodity prices, foreign currency risk and interest rate risk, as well as liquidity risk and credit risk.

The company maintains a formal governance process to manage its financial risks. Our Risk Management Committee (RMC) is charged with the oversight of the company's risk management for trading risk management activities which are defined as strategic hedging, optimization trading, marketing and speculative trading. The RMC, acting under board authority, meets regularly to monitor limits on risk exposures, review policy compliance and validate risk-related methodologies and procedures. All risk management activity is carried out by specialist teams that have the appropriate skills, experience and supervision with the appropriate financial and management controls, and is unchanged from the prior year.

1) Market Risk

Market risk is the risk or uncertainty arising from possible market price movements and their impact on the future performance of the business. The market price movements that could adversely affect the value of the company's financial assets, liabilities and expected future cash flows include commodity price risk (crude oil, natural gas and electricity price), foreign currency exchange risk and interest rate risk.

(a) Commodity Price Risk

The company's financial performance is closely linked to crude oil prices (including pricing differentials for various product types), and to a lesser extent, natural gas and electricity prices. The company's policies permit the use of various financial instruments in managing these price exposures. Our strategic crude oil hedging program gives management approval to fix a price or range of prices for portions of the total crude oil planned production for specified periods of time. Historically, the company has leveraged hedging instruments to stabilize cash flows during periods of growth and expansion. The company will consider additional strategic hedging opportunities as they become available.

A key component of our overall business strategy is to produce sufficient natural gas to meet or exceed internal demands for natural gas purchased for consumption in our oil sands operation, thus creating a price hedge which reduces our exposure to natural gas price volatility. In addition, existing corporate policies also permit the hedging of natural gas exposures to manage regional price differentials and pricing indexes as identified.

Changes in commodity prices on our financial contracts would have the following impact on our net earnings and other comprehensive income for the twelve months ended December 31, 2008:

Sensitivity Analysis

($ millions)	December 31, 2008 (1)	Change	Net Earnings	Other Comprehensive Income
Crude Oil	US$63.38/barrel			
Price increase		US$1.00/barrel	(32)	—
Price decrease		US$1.00/barrel	32	—
Natural Gas	US$6.22/mcf			
Price increase		US$0.10/mcf	(1)	—
Price decrease		US$0.10/mcf	1	—

(1) Prices represent the average of the forward strip prices at December 31, 2008.

(b) Foreign Currency Exchange Risk

The company is exposed to changes in foreign exchange rates as revenues, capital expenditures, or financial instruments may fluctuate due to changing rates. As crude oil, the company's primary product, is priced in U.S. dollars, fluctuations in US$/Cdn$ exchange rates may have a significant impact on revenues. The company's exposure is partially offset through the issuance of U.S. dollar denominated long-term debt (refer to note 6) and by sourcing capital projects in U.S. dollars. The company does not currently hedge foreign currency risk on estimated revenues. The effect of a $0.01 change in the US$/Cdn$ exchange rate on our U.S. dollar denominated long-term debt would change after-tax earnings by approximately $55 million for the twelve months ended December 31, 2008.

Where an operating unit has substantial exposure to capital expenditures in currencies other than the U.S. dollar, the company may hedge these risks through a combination of forward and option instruments. Transactions in the applicable financial market are executed consistent with established risk management policies.

(c) Interest Rate Risk

The company is exposed to interest rate risk as changes in interest rates may affect future cash flows and the fair values of its financial instruments. The primary exposure is related to notes and commercial paper. The company seeks to optimize this risk through the use of interest rate swaps by swapping fixed rates of interest for variable rates (see – fair value hedges) and other derivative instruments.

To optimize the company's position with respect to interest expense, the company targets 30% to 50% of total debt to be exposed to floating interest rates. Over time this floating/fixed rate mix will fluctuate based on prevailing market conditions and management's assessment of overall risk.

The proportion of floating interest rate exposure inclusive of interest rate swaps at December 31, 2008 was 15% of total debt outstanding (December 31, 2007 was 19% of total debt outstanding). The weighted average interest rate on total debt for the year ending December 31, 2008 was 5.9% (December 31, 2007 – 6.1%).

The company's cash flows are sensitive to changes in interest rates on the floating rate portion of the company's debt. Given our current growth and expansion plans, all interest is currently being capitalized and therefore there is no earnings impact. If the interest rates applicable to floating rate instruments were to have increased by 1%, it is estimated that the company's cash flow for the twelve months ended December 31, 2008 would decrease by approximately $11 million. This assumes that the amount and mix of fixed and floating rate debt remains unchanged from December 31, 2008, and that the change in interest rates is effective from the beginning of the period.

2) Liquidity Risk

Liquidity risk is the risk that an entity will encounter difficulty in meeting obligations associated with financial liabilities. The company believes that it has access to sufficient capital through internally generated cash flows and external sources (bank credit markets and debt capital markets), and to undrawn committed borrowing facilities to meet current spending forecasts.

Surplus cash is invested into a range of short-dated money market securities and the company seeks to ensure the security and liquidity of those investments. Investments are only permitted in high credit quality government or corporate securities. Diversification of these investments is supported through maintaining counterparty credit limits.

The following table shows the timing of cash outflows relating to trade and other payables and finance debt.

	December 31, 2008		December 31, 2007	
($ millions)	Trade and other payables (1)	Finance debt (2)	Trade and other payables (1)	Finance debt (2)
Within one year	**3 181**	**1 378**	2 843	764
1 to 3 years	**335**	**1 377**	347	427
3 to 5 years	**—**	**822**	—	917
Over 5 years	**16**	**13 387**	19	6 985
Total	**3 532**	**16 964**	3 209	9 093

(1) These balances exclude non-financial liabilities (pension liabilities, asset retirement obligation, future income taxes and derivative financial instruments) totaling $1,972 million and $1,375 million at December 31, 2008 and December 31, 2007 respectively.

(2) Finance debt includes long-term debt, capital leases and interest payments on fixed-term debt and commercial paper.

3) Credit Risk

Credit risk is the risk that a customer or counterparty will fail to perform an obligation or fail to pay amounts due causing a financial loss. We have a credit policy that is designed to ensure there is a standard credit practice throughout the company to measure and monitor credit risk. The policy outlines delegation of authority, the due diligence process required to approve a new customer or counterparty and the maximum amount of credit exposure per single entity. Before transactions begin with a new customer or counterparty, its creditworthiness is assessed, a credit rating is assigned and a maximum credit limit is allocated. The assessment process is outlined in the credit policy and considers both quantitative and qualitative factors. The company constantly monitors the exposure to any single customer or counterparty along with the financial position of the customer or counterparty. If it is deemed that a customer or counterparty has become materially weaker, the company will work to reduce the credit exposure and lower the credit limit allocated. Regular reports are generated to monitor credit risk and the Credit Committee meets quarterly to ensure compliance with the credit policy and review the exposures.

A substantial portion of the company's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risk. At December 31, 2008 and December 31, 2007, substantially all of the company's trade receivables were current, and there were no counterparties that individually constituted more than 10% of the outstanding balance.

The company may be exposed to certain losses in the event that counterparties to derivative financial instruments are unable to meet the terms of the contracts. The company's exposure is limited to those counterparties holding derivative contracts with positive fair values at the reporting date. At December 31, 2008, the company's exposure was $659 million (December 31, 2007 – $38 million).

8. CAPITAL STRUCTURE FINANCIAL POLICIES

The company's primary capital management objective is to maintain a solid investment-grade credit rating profile. This objective affords the company the financial flexibility and access to the capital it requires to execute on its growth objectives.

The company monitors capital through two key ratios: net debt to cash flow from operations and total debt to total debt plus shareholders' equity.

Net debt to cash flow from operations is calculated as short-term debt plus long-term debt less cash and cash equivalents divided by cash flow from operations for the year then ended.

Total debt to total debt plus shareholders' equity is calculated as short-term debt plus long-term debt divided by short-term debt plus long-term debt plus shareholders' equity.

The company's strategy during 2008, which was unchanged from 2007, was to maintain the measures set out in the following schedule. The company believes that maintaining our capital targets helps to provide the company access to capital at a reasonable cost by maintaining solid investment-grade credit ratings. The company operates in a cyclical business environment and manages this through the business cycle.

At December 31, ($ millions)	Capital Measure Target	**2008**	2007
Components of ratios			
Short-term debt		**11**	6
Long-term debt		**7 875**	3 811
Total debt		**7 886**	3 817
Cash and equivalents		**660**	569
Net debt		**7 226**	3 248
Shareholders' equity		**14 523**	11 896
Total capitalization (total debt + shareholders' equity)		**22 409**	15 713
Cash flow from operations		**4 463**	4 009
Net debt/cash flow from operations	<2.0 times	**1.6**	0.8
Total debt/total debt plus shareholders' equity		**35%**	24%

9. ACCRUED LIABILITIES AND OTHER

($ millions)	**2008**	2007
Asset retirement obligations [a]	**1 444**	882
Employee future benefits liability (see note 10)	**191**	176
Employee and director incentive plans [b]	**67**	173
Deferred revenue	**161**	164
Environmental remediation costs [c]	**7**	11
Other	**116**	28
Total	**1 986**	1 434

(a) Asset Retirement Obligations (ARO)

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the total obligations associated with the retirement of property, plant and equipment.

($ millions)	**2008**	2007
Asset retirement obligations, beginning of year	**1 072**	808
Liabilities incurred	**598**	275
Liabilities settled	**(134)**	(59)
Accretion of asset retirement obligations	**64**	48
Asset retirement obligations, end of year	**1 600**	1 072

The portion of the ARO expected to be paid within one year is shown within current liabilities and amounts to an additional $156 million (2007 – $190 million).

The total undiscounted amount of estimated future cash flows required to settle the obligations at December 31, 2008, was approximately $3.5 billion (2007 – $2.2 billion). The liability recognized in 2008 was discounted using the company's credit-adjusted risk-free rate of 9.0% (2007 – 6.0%). Payments to settle the ARO occur on an ongoing basis and will continue over the lives of the operating assets, which can exceed 30 years.

A significant portion of the company's assets, including the upgrading facilities at the oil sands operation and the two downstream refineries located in Sarnia and Commerce City, have retirement obligations for which the fair value cannot be reasonably determined because the assets currently have an indeterminate life. The asset retirement obligation for these assets will be recorded in the first period in which the lives of the assets are determinable.

(b) Employee and Director Incentive Plans

The portion of the employee and director incentive plans expected to be paid within one year is shown within current liabilities and amounts to an additional $8 million (2007 – $50 million).

(c) Environmental Remediation Costs

The portion of the environmental remediation costs expected to be paid within one year is shown within current liabilities and amounts to an additional $16 million (2007 – $19 million). Environmental remediation costs are obligations assumed through the purchase of the Commerce City refineries.

10. EMPLOYEE FUTURE BENEFITS LIABILITY

*Suncor employees are eligible to receive certain pension, health care and insurance benefits when they retire. The related **Benefit Obligation** or commitment that Suncor has to employees and retirees at December 31, 2008, was $955 million (2007 – $1,063 million).*

*As required by government regulations, Suncor sets aside funds with an independent trustee to meet certain of the pension obligations. The company funds its unregistered supplementary pension plan and supplementary senior executive retirement plan on a voluntary basis. The amount and timing of future funding for these supplementary plans is subject to capital availability and is at the company's discretion. At the end of December 2008, **Plan Assets** to meet the **Benefit Obligation** were $613 million (2007 – $684 million).*

*The excess of the **Benefit Obligation** over **Plan Assets** of $342 million (2007 – $379 million) represents the **Net Unfunded Obligation**.*

See below for more technical details and amounts.

Defined Benefit Pension Plans and Other Post-Retirement Benefits

The company's defined benefit pension plans provide non-indexed pension benefits at retirement based on years of service and final average earnings. These obligations are met through funded registered retirement plans and through unregistered supplementary pensions and senior executive retirement plans that are voluntarily funded through retirement compensation arrangements, and/or paid directly to recipients. Company contributions to the funded plans are deposited with independent trustees who act as custodians of the plans' assets, as well as the disbursing agents of the benefits to recipients. Plan assets are managed by a pension committee on behalf of beneficiaries. The committee retains independent managers and advisors.

Funding of the registered retirement plans complies with applicable regulations that require actuarial valuations of the pension funds at least once every three years in Canada, depending on funding status, and every year in the United States. The most recent valuation for the Canadian plan was performed as at December 31, 2006.

The company's other post-retirement benefits programs are unfunded and include certain health care and life insurance benefits provided to retired employees and eligible surviving dependants.

The expense and obligations for both funded and unfunded benefits are determined in accordance with Canadian GAAP and actuarial principles. Obligations are based on the projected benefit method of valuation that includes employee service to date and present pay levels, as well as a projection of salaries and service to retirement.

Obligations and Funded Status

The following table presents information about obligations recognized in the Consolidated Balance Sheets and the funded status of the plans at December 31:

($ millions)	Pension Benefits **2008**	Pension Benefits 2007	Other Post-Retirement Benefits **2008**	Other Post-Retirement Benefits 2007
Change in benefit obligation				
Benefit obligation at beginning of year	**901**	866	**162**	158
Service costs	**56**	51	**4**	4
Interest costs	**49**	45	**9**	8
Plan participants' contributions	**9**	5	**—**	—
Foreign exchange	**8**	(5)	**4**	(2)
Actuarial (gain) loss	**(168)**	(28)	**(27)**	(3)
Benefits paid	**(49)**	(33)	**(3)**	(3)
Benefit obligation at end of year [(a)(d)]	**806**	901	**149**	162
Change in plan assets [(b)]				
Fair value of plan assets at beginning of year	**684**	616	**—**	—
Actual return (loss) on plan assets	**(107)**	7	**—**	—
Employer contributions	**69**	88	**—**	—
Foreign exchange	**4**	(2)	**—**	—
Plan participants' contributions	**9**	5	**—**	—
Benefits paid	**(46)**	(30)	**—**	—
Fair value of plan assets at end of year [(d)]	**613**	684	**—**	—
Net unfunded obligation	**(193)**	(217)	**(149)**	(162)
Items not yet recognized in earnings:				
Unamortized net actuarial loss [(c)]	**123**	158	**12**	43
Unamortized past service costs	**—**	—	**(17)**	(20)
Accrued benefit liability	**(70)**	(59)	**(154)**	(139)
Current liability	**(37)**	(41)	**(3)**	(3)
Long-term liability	**(40)**	(40)	**(151)**	(136)
Long-term asset	**7**	22	**—**	—
Total accrued benefit liability	**(70)**	(59)	**(154)**	(139)

(a) Obligations are based on the following assumptions:

(percent)	Pension Benefit Obligations **2008**	Pension Benefit Obligations 2007	Other Post-Retirement Benefits Obligations **2008**	Other Post-Retirement Benefits Obligations 2007
Discount rate	**6.50**	5.25	**6.50**	5.25
Rate of compensation increase	**5.00**	5.00	**4.75**	4.75

A one percent change in the assumptions at which pension benefits and other post-retirement benefits liabilities could be effectively settled is as follows:

($ millions)	Rate of Return on Plan Assets 1% increase	Rate of Return on Plan Assets 1% decrease	Discount Rate 1% increase	Discount Rate 1% decrease	Rate of Compensation Increase 1% increase	Rate of Compensation Increase 1% decrease
Increase (decrease) to net periodic benefit cost	(6)	6	(23)	27	11	(9)
Increase (decrease) to benefit obligation	—	—	(127)	150	32	(29)

In order to measure the expected cost of other post-retirement benefits, a 9% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2008 (2007 – 9%; 2006 – 9.5%). It is assumed that this rate will remain constant in 2009 and will decrease by 0.5% annually, to 5% by 2017, and remain at that level thereafter.

Assumed health care cost trend rates may have a significant effect on the amounts reported for other post-retirement benefit obligations. A one percent change in assumed health care cost trend rates would have the following effects:

($ millions)	1% increase	1% decrease
Increase (decrease) to total of service and interest cost components of net periodic post-retirement health care benefit cost	1	(1)
Increase (decrease) to the health care component of the accumulated post-retirement benefit obligation	16	(13)

(b) Pension plan assets are not the company's assets and therefore are not included in the Consolidated Balance Sheets.

(c) The unamortized net actuarial loss represents annually calculated differences between actual and projected plan performance. These amounts are amortized as part of the net periodic benefit cost over the expected average remaining service life of employees of 11 years for pension benefits (2007 – 11 years; 2006 – 11 years), and over the expected average future service life to full eligibility age of 11 years for other post-retirement benefits (2007 – 12 years; 2006 – 10 years).

(d) The company uses a measurement date of December 31 to value the plan assets and accrued benefit obligation.

The above benefit obligation at year-end includes partially funded and unfunded plans, as follows:

	Pension Benefits		Other Post-Retirement Benefits	
($ millions)	**2008**	2007	**2008**	2007
Partially funded plans	**806**	901	**—**	—
Unfunded plans	**—**	—	**149**	162
Benefit obligation at end of year	**806**	901	**149**	162

Components of Net Periodic Benefit Cost (i)

	Pension Benefits			Other Post-Retirement Benefits		
($ millions)	**2008**	2007	2006	**2008**	2007	2006
Current service costs	**56**	51	44	**4**	4	5
Interest costs	**49**	45	40	**9**	8	8
Expected return on plan assets (ii)	**(45)**	(42)	(32)	**—**	—	—
Amortization of net actuarial loss	**22**	25	28	**3**	3	1
Net periodic benefit cost recognized (iii)	**82**	79	80	**16**	15	14

Components of Net Incurred Benefit Cost (i)

	Pension Benefits			Other Post-Retirement Benefits		
($ millions)	**2008**	2007	2006	**2008**	2007	2006
Current service costs	**56**	51	44	**4**	4	5
Interest costs	**49**	45	40	**9**	8	8
Actual (return) loss on plan assets (ii)	**107**	(7)	(60)	**—**	—	—
Actuarial (gain) loss	**(168)**	(28)	67	**(27)**	(4)	5
Net incurred benefit cost	**44**	61	91	**(14)**	8	18

(i) The net periodic benefit cost includes certain accounting adjustments made to allocate costs to the periods in which employee services are rendered, consistent with the long-term nature of the benefits. Costs actually incurred in the period (arising from actual returns on plan assets and actuarial gains and losses in the period) differ from allocated costs recognized.

(ii) The expected return on plan assets is the expected long-term rate of return on plan assets for the year. It is based on plan assets at the beginning of the year that have been adjusted on a weighted-average basis for contributions and benefit payments expected for the year. The expected return on plan assets is included in the net periodic benefit cost for the year to which it relates, while the difference between it and the actual return realized on plan assets in the same year is amortized over the expected average remaining service life of employees of 11 years for pension benefits.

To estimate the expected long-term rate of return on plan assets, the company considered the current level of expected returns on the fixed income portion of the portfolio, the historical level of the risk premium associated with other asset classes in which the portfolio is invested and the expectation for future returns on each asset class. The expected return for each asset class was weighted based on the policy asset mix to develop an expected long-term rate of return on asset assumption for the portfolio.

(iii) Pension expense is based on the following assumptions:

	Pension Benefit Expense			Other Post-Retirement Benefits Expense		
(percent)	**2008**	2007	2006	**2008**	2007	2006
Discount rate	**5.25**	5.00	5.00	**5.25**	5.00	5.00
Expected return on plan assets	**6.50**	6.50	6.50	**N/A**	N/A	N/A
Rate of compensation increase	**5.00**	5.00	4.50	**4.75**	4.75	4.25

Plan Assets and Investment Objectives

The company's long-term investment objective is to secure the defined pension benefits while managing the variability and level of its contributions. The portfolio is rebalanced periodically as required, while ensuring that the maximum equity content is 65% at any time. Plan assets are restricted to those permitted by legislation, where applicable. Investments are made through pooled, mutual, segregated or exchange traded funds.

The company's weighted-average pension plan asset allocation based on market values as at December 31, 2008 and 2007, and the target allocation for 2009, are as follows:

	Target Allocation %	Plan Assets %	
Asset Category	2009	**2008**	2007
Equities	60	**57**	58
Fixed income	40	**43**	42
Total	100	**100**	100

Equity securities do not include any direct investments in Suncor shares.

Cash Flows

The company expects that contributions to its pension plans in 2009 will be $76 million, including approximately $10 million for the company's supplemental executive and supplemental retirement plans. Expected benefit payments from all of the plans are as follows:

	Pension Benefits	Other Post-Retirement Benefits
2009	42	6
2010	45	6
2011	47	7
2012	50	8
2013	54	9
2014 – 2018	318	51
Total	556	87

Defined Contribution Pension Plan

The company has a Canadian defined contribution plan and a U.S. 401(k) savings plan, under which both the company and employees make contributions. Company contributions and corresponding expense totalled $15 million in 2008 (2007 – $13 million; 2006 – $11 million).

11. INCOME TAXES

The assets and liabilities shown on Suncor's balance sheets are calculated in accordance with Canadian GAAP. Suncor's income taxes are calculated according to government tax laws and regulations, which results in different values for certain assets and liabilities for income tax purposes. These differences are known as ***temporary differences****, because eventually these differences will reverse.*

The amount shown on the balance sheets as ***future income taxes*** *represent income taxes that will eventually be payable or recoverable in future years when these temporary differences reverse.*

See below for more technical details and amounts.

The provision for income taxes reflects an effective tax rate that differs from the statutory tax rate. A reconciliation of the provision for income taxes is as follows:

($ millions)	**2008 Amount**	2007 Amount	2006 Amount
Federal tax rate	**924**	1 119	1 253
Provincial abatement	**(313)**	(308)	(380)
Federal surtax	**—**	34	43
Provincial tax rates	**314**	325	394
Statutory tax	**925**	1 170	1 310
Adjustment of statutory rate for future rate reductions	**(101)**	(151)	(150)
	824	1 019	1 160
Add (deduct) the tax effect of:			
Capital gains and losses	**136**	(40)	—
Stock-based compensation	**36**	33	18
Other	**47**	(18)	16
Assessments and adjustments	**(48)**	(1)	(9)
Tax rate changes on opening future income taxes [(a)]	**—**	(427)	(419)
Crown royalties	**—**	—	125
Large corporations tax	**—**	—	2
Attributed Canadian royalty income	**—**	—	(23)
Resource allowance [(b)]	**—**	—	(42)
Total provision for income taxes	**995**	566	828
Effective Rate	**32%**	16%	22%

(a) During 2007, the federal government enacted tax rate reductions totalling $427 million. During the fourth quarter of 2007 the federal government substantively enacted a 3.5% reduction to its federal corporate tax rates. Accordingly, the company recognized a reduction in future income tax expense of $360 million related to the revaluation of its opening future income tax balances. During the second quarter of 2007 the federal government substantively enacted a 0.5% reduction to its federal corporate tax rates. Accordingly, the company recognized a reduction in future income tax expense of $67 million related to the revaluation of its opening future income tax balances.

During 2006, there were both federal and provincial government rate reductions totalling $419 million. 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. As well, the provincial government of Alberta substantively enacted a 1.5% reduction to its provincial corporate tax rates during the second quarter of 2006. 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.

(b) The resource allowance was a federal tax deduction allowed as a proxy for non-deductible provincial Crown royalties. As required by GAAP in Canada, resource allowance is accounted for by adjusting the statutory tax rate by the resource allowance rate. Resource allowance has been phased out effective January 1, 2007.

In 2008, net income tax payments totalled $638 million (2007 – $152 million; 2006 – $36 million).

At December 31, future income taxes were comprised of the following:

($ millions)	**2008**	2007
Future income tax liabilities:		
Excess of book values of assets over tax values	**4 987**	4 467
Risk management	**149**	—
Other	**48**	86
Future income tax assets:		
Asset retirement obligations	**(400)**	(269)
Employee future benefits	**(72)**	(118)
Inventories	**(7)**	37
Net Future income tax liabilities	**4 705**	4 203
Less: Current portion of future income tax assets & liabilities	**90**	(9)
Future income tax liabilities	**4 615**	4 212

12. COMMITMENTS, CONTINGENCIES, VARIABLE INTEREST ENTITIES, GUARANTEES AND SUBSEQUENT EVENT

(a) Operating Commitments

In order to ensure continued availability of, and access to, facilities and services to meet its operational requirements, the company periodically enters into transportation service agreements for pipeline capacity and energy services agreements as well as non-cancellable operating leases for service stations, office space and other property and equipment. Under contracts existing at December 31, 2008, future minimum amounts payable under these leases and agreements are as follows:

($ millions)	Pipeline Capacity and Energy Services (1)	Operating Leases
2009	327	56
2010	341	49
2011	421	39
2012	409	28
2013	412	24
Later years	5 826	176
Total	7 736	372

(1) Includes annual tolls payable under transportation service agreements with major pipeline companies to use a portion of their pipeline capacity and tankage, as applicable, for transportation of product within Canada and the USA.

Suncor has commitments under long-term energy agreements to obtain a portion of the power and the steam generated by certain cogeneration facilities owned by a major third-party energy company. Since October 1999, this third-party has also managed the operations of Suncor's existing energy services facility at its oil sands operations.

At December 31, 2008, Suncor had purchase commitments relating to crude oil predominately for refinery supply and natural gas for physical trading. Crude oil commitments consisted of market price evergreen contracts for a total volume of 148,000 barrels per day of crude oil (2007 – 148,000 bbls/day), of which most have industry standard 30-day cancellation clauses. Natural gas commitments consist of fixed price contracts with a total volume of 8 million GJ (2007 – 14 million) within a price range of Cdn $5.80 – $9.47 per GJ (2007 – $6.00-$7.67 per GJ) and having terms extending to December 2009 (2007 – December 2008), as well as market price contracts for a total volume of 17 million GJ (2007 – 40 million GJ) with terms extending to October 2009 (2007 – April 2009).

(b) Contingencies

The company is subject to various regulatory and statutory requirements relating to the protection of the environment. These requirements, in addition to contractual agreements and management decisions, result in the recognition of estimated asset retirement obligations. Estimates of asset retirement obligation costs can change significantly based on such factors as operating experience and changes in legislation and regulations.

The company carries both property damage and business interruption insurance policies with a combined coverage limit of up to US$1.6 billion, net of deductible amounts or waiting periods. The primary property loss policy of US$250 million has a deductible of US$10 million per incident. Suncor has 100% ownership interest in Fort Insurance Limited, an insurance company which provides coverage to Suncor including business interruption coverage for oil sands with a limit of US$150 million and a deductible of the greater of 30 days or US$50 million. The excess coverage of US$1.2 billion can be used for either property damage or business interruption coverage for oil sands operations. Excess business interruption coverage begins the greater of

90 days from the date of the incident or US$250 million in gross earnings lost. For the purposes of determining loss for business interruption claims, the excess coverage has a ceiling of US$50 WTI and a lost production maximum of 150,000 barrels per day.

The company is defendant and plaintiff in a number of legal actions that arise in the normal course of business. The company believes that any liabilities that might arise pertaining to such matters would not have a material effect on its consolidated financial position.

Costs attributable to these commitments and contingencies are expected to be incurred over an extended period of time and to be funded from the company's cash flow from operating activities. Although the ultimate impact of these matters on net earnings cannot be determined at this time, the impact may be material.

(c) Guarantees, Variable Interest Entities (VIE), and Off-Balance Sheet Arrangements

At December 31, 2008, the company had various indemnification agreements with third parties as described below.

The company had a securitization program in place to sell, on a revolving, fully serviced and limited recourse basis, up to $170 million of accounts receivable (2007 – $170 million) having a maturity of 45 days or less, to a third party. The third party was a multiple party securitization vehicle that provided funding for numerous asset pools. As at December 31, 2008, no outstanding accounts receivable had been sold under the program (2007 – nil) and the program had been allowed to expire. Although the company does not believe it had any significant exposure to credit losses, under the recourse provisions, the company provided indemnification against potential credit losses for certain counterparties. This indemnification did not exceed $57 million in 2008 and no contingent liability or earnings impact were recorded for this indemnification as the company believes it had no significant exposure to credit losses. Proceeds received from new securitizations and proceeds from collections reinvested in securitizations on a revolving basis for the year ended December 31, 2008, were $170 million and approximately $510 million, respectively. The company recorded an after-tax loss of approximately $2 million on the securitization program in 2008 (2007 – $4 million; 2006 – $2 million).

In 1999, the company entered into an equipment sale and leaseback arrangement with a VIE for proceeds of $30 million. The VIE's sole asset is the equipment sold to it and leased back by the company. The VIE was consolidated effective January 1, 2005. The initial lease term covered a period of seven years and had been accounted for as an operating lease. The company repurchased the equipment in 2006 for $21 million. As at December 31, 2008 and 2007, the VIE did not have any assets or liabilities.

The company has agreed to indemnify holders of the 6.10% notes, 6.85% notes, 6.50% notes, 7.15% notes, and the 5.95% notes and the company's credit facility lenders (see note 6) for added costs relating to taxes, assessments or other government charges or conditions, including any required withholding amounts. Similar indemnity terms apply to certain facility and equipment leases.

There is no limit to the maximum amount payable under the indemnification agreements described above. The company is unable to determine the maximum potential amount payable as government regulations and legislation are subject to change without notice. Under these agreements, Suncor has the option to redeem or terminate these contracts if additional costs are incurred.

(d) Subsequent Event

Subsequent to December 31, 2008, the company entered into crude oil hedges for approximately 125,000 barrels per day (bpd) of production from February 1 through December 31, 2009. These volumes are in addition to previously reported options to sell 55,000 bpd at an equivalent WTI floor price of US$60.00 per barrel from January 1 to December 31, 2009. The combination of the previous options and new fixed-price hedges provide Suncor with an equivalent WTI floor price of about US$53.50 for approximately 180,000 bpd of production in 2009.

For the full year 2010, we have entered into crude oil hedges for approximately 50,000 bpd at an equivalent WTI floor price of US$50.00 per barrel and a ceiling price of approximately US$68.00 per barrel. This program replaces previously reported 2010 options to sell 55,000 bpd at an equivalent WTI floor price of US$60.00, which was effectively exited by selling similar contracts for gross proceeds to Suncor of approximately $250 million before tax.

13. SHARE CAPITAL

Stock Split

In May 2008, the company implemented a two-for-one stock split of its issued and outstanding common shares. Information related to common shares, stock-based compensation, and earnings per share has been restated to reflect the impact of the company's two-for-one stock split.

Authorized

Common Shares

The company is authorized to issue an unlimited number of common shares without nominal or par value.

Preferred Shares

The company is authorized to issue an unlimited number of preferred shares in series, without nominal or par value.

Issued

	Common Shares Number (thousands)	Amount ($ millions)
Balance as at December 31, 2005	915 330	732
Issued for cash under stock option plans	4 294	52
Issued under dividend reinvestment plan	264	10
Balance as at December 31, 2006	919 888	794
Issued for cash under stock option plans	5 388	74
Issued under dividend reinvestment plan	290	13
Balance as at December 31, 2007	925 566	881
Issued for cash under stock options plan	**9 823**	**226**
Issued under dividend reinvestment plan	**135**	**6**
Balance as at December 31, 2008	**935 524**	**1 113**

Stock-Based Compensation

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

After the date of grant, employees and non-employee directors that hold options must earn the right to exercise them. This is done by the holder by fulfilling a time requirement for service to the company, and with respect to certain options, subject to accelerated vesting should the company meet predetermined performance criterion. 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 options are 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 restricted share unit is a time-vested award with a three-year term entitling employees to receive cash.

See below for more technical details and amounts on the company's stock option plans:

(a) Stock Option Plans

(i) SunShare 2012 Performance Stock Option Plan

The company granted 2,637,000 options in 2008 (2007 – 15,686,000, 2006 – nil) to all eligible permanent full-time and part-time employees, both executive and non-executive, under its new employee stock option incentive plan ("SunShare 2012"). During the second quarter 2008, in connection with the achievement of a predetermined performance criterion, 25% of the outstanding options vested under the SunShare 2012 plan and will become exercisable on January 1, 2010. The remaining 75% of outstanding options may vest on January 1, 2013 if further specified performance targets are met. All unvested options at January 1, 2013, which have not previously expired or been cancelled will automatically expire.

(ii) SunShare Performance Stock Option Plan

Granting of options under the company's previous employee stock option incentive plan ("SunShare") ended in December 2007 (the company granted 2,090,000 options during 2007 and 3,274,000 options during 2006). Final vesting of all unvested SunShare options occurred on April 30, 2008.

(iii) Executive Stock Plan

Under this plan, the company granted 895,000 common share options in 2008 (2007 – 958,000; 2006 – 1,076,000) to non-employee directors and certain executives and other senior employees of the company. Options granted have a 10-year life and vest annually over a three-year period.

(iv) Key Contributor Stock Option Plan

Under this plan, the company granted 2,375,000 common share options in 2008 (2007 – 2,370,000; 2006 – 2,100,000) to non-insider senior managers and key employees. Options granted have a 10-year life and vest annually over a three-year period.

The following tables cover all common share options granted by the company for the years indicated:

	Number (thousands)	Range of Exercise Prices Per Share ($)	Weighted-Average Exercise Price Per Share ($)
Outstanding, December 31, 2005	38 406	2.61 – 35.57	14.06
Granted	6 448	36.68 – 50.90	44.98
Exercised	(4 294)	2.61 – 30.96	10.50
Cancelled	(942)	12.50 – 48.05	23.33
Outstanding, December 31, 2006	39 618	3.89 – 50.90	19.24
Granted	21 104	35.28 – 53.51	46.68
Exercised	(5 388)	3.89 – 46.06	11.38
Cancelled	(1 334)	12.66 – 50.87	32.84
Outstanding, December 31, 2007	54 000	5.06 – 53.51	30.31
Granted	**5 907**	**23.30 – 69.97**	**50.78**
Exercised	**(9 823)**	**5.06 – 50.86**	**19.69**
Cancelled	**(3 682)**	**12.31 – 67.58**	**41.72**
Outstanding, December 31, 2008	**46 402**	**5.06 – 69.97**	**34.55**
Exercisable, December 31, 2008	**24 933**	**5.06 – 50.86**	**22.55**

Common shares authorized for issuance by the Board of Directors that remain available for the granting of future options, at December 31:

(thousands of common shares)	**2008**	2007	2006
	12 345	14 570	15 940

The following table is an analysis of outstanding and exercisable common share options as at December 31, 2008:

	Outstanding			Exercisable	
Exercise Prices ($)	Number (thousands)	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price Per Share ($)	Number (thousands)	Weighted-Average Exercise Price Per Share ($)
5.06 – 8.72	1 723	2	8.29	1 723	8.29
10.67 – 14.46	11 523	3	13.48	11 523	13.48
15.64 – 34.86	5 439	5	20.60	5 417	20.59
35.26 – 46.84	8 127	6	44.34	5 506	44.31
47.02 – 47.91	16 136	6	47.54	345	47.43
48.05 – 83.58	3 454	6	56.22	419	49.59
Total	46 402	5	34.55	24 933	22.55

Fair Value of Options Granted

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

	2008	2007	2006
Annual dividend per share	**$0.20**	$0.19	$0.15
Risk-free interest rate	**3.35%**	4.22%	4.08%
Expected life	**6 years**	6 years	5 years
Expected volatility	**30%**	30%	29%
Weighted-average fair value per option	**$13.86**	$14.89	$14.59

Stock-based compensation expense recognized for the year ended December 31, 2008 related to stock option plans was $120 million (2007 – $103 million; 2006 – $53 million).

Common share options granted prior to January 1, 2003 are not recognized as compensation expense in the Consolidated Statement of Earnings and Comprehensive Income. 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)	**2008**	2007	2006
Net earnings attributable to common shareholders – as reported	**2 137**	2 983	2 969
Less: compensation cost under the fair value method for pre-2003 options	**4**	8	15
Pro forma net earnings attributable to common shareholders for pre-2003 options	**2 133**	2 975	2 954
Basic earnings per share			
As reported	**2.29**	3.23	3.23
Pro forma	**2.29**	3.23	3.22
Diluted earnings per share			
As reported	**2.26**	3.17	3.16
Pro forma	**2.26**	3.16	3.14

(b) Deferred Share Units (DSUs)

The company had 1,903,000 DSUs outstanding at December 31, 2008 (2,336,000 at December 31, 2007). DSUs were granted to certain executives under the company's former employee long-term incentive program. Members of the Board of Directors receive one-half, or at their option, all of their compensation in the form of DSUs. DSUs are only redeemable at the time a unitholder ceases employment or Board membership, as applicable.

In 2008, 473,000 DSUs were redeemed for cash consideration of $30 million (2007 – 40,000 redeemed for cash consideration of $2 million; 2006 – 118,000 redeemed for cash consideration of $5 million). Over time, DSU unitholders are entitled to receive additional DSUs equivalent in value to future notional dividend reinvestments. Final DSU redemption amounts are subject to change depending on the company's share price at the time of exercise. Accordingly, the company revalues the DSUs on each reporting date, with any changes in value recorded as an adjustment to compensation expense in the period. As at December 31, 2008, the total liability related to the DSUs was $45 million (2007 – $126 million), of which $8 million (2007 – $5 million) was classified as current.

During 2008, total pretax compensation expense related to DSUs was a recovery of $51 million (2007 – $21 million; 2006 – $25 million).

(c) Performance Share Units (PSUs)

During 2008, the company issued 795,000 PSUs (2007 – 830,000; 2006 – 794,000) under its Performance Share Unit Compensation Plan. PSUs granted replace the remuneration value of reduced grants under the company's stock option plans. PSUs vest and are settled in cash approximately three years after the grant date to varying degrees (0%, 50%, 100% and 150%) contingent upon Suncor's performance (performance factor). Performance is measured by reference to the company's total shareholder return (stock price appreciation and dividend income) relative to a peer group of companies. Expense related to the PSUs is accrued based on the price of common shares at the end of the period and the anticipated performance factor. This expense is recognized on a straight-line basis over the term of the grant. Pretax recovery recognized for PSUs during 2008 was $30 million (2007 – expense of $60 million; 2006 – expense of $42 million).

(d) SunShare 2012 Restricted Share Units (RSUs)

In 2008, the company issued 1,078,000 RSUs under the share unit portion of its new employee stock-based compensation plan ("SunShare 2012"). Expense recognized for the year ended December 31, 2008 was $8 million.

14. EARNINGS PER COMMON SHARE

The following is a reconciliation of basic and diluted net earnings per common share:

($ millions)	**2008**	2007	2006
Net earnings attributable to common shareholders	**2 137**	2 983	2 969

(millions of common shares)			
Weighted-average number of common shares	**932**	922	918
Dilutive securities:			
Shares issued under stock-based compensation plans	**13**	20	22
Weighted-average number of diluted common shares	**945**	942	940

(dollars per common share)			
Basic earnings per share [(a)]	**2.29**	3.23	3.23
Diluted earnings per share [(b)]	**2.26**	3.17	3.16

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 the net earnings attributable to common shareholders divided by the weighted-average number of common shares.

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

15. FINANCING EXPENSES (INCOME)

($ millions)	**2008**	2007	2006
Interest expense on debt	**352**	189	150
Capitalized interest	**(352)**	(189)	(129)
Net interest expense	**—**	—	21
Foreign exchange loss (gain) on long-term debt	**919**	(252)	—
Other foreign exchange (gain) loss	**(2)**	41	18
Total financing expenses (income)	**917**	(211)	39

Cash interest payments in 2008 totaled $328 million (2007 – $183 million; 2006 – $146 million).

16. INVENTORIES

($ millions)	**2008**	2007
Crude oil	**459**	542
Refined products	**247**	320
Materials, supplies and merchandise	**203**	150
Total	**909**	1 012

During 2008, inventories of $15.7 billion (2007 – $8.0 billion) were expensed which includes write-downs of inventories totaling $39.9 million (2007 – $15.2 million). No reversals of write-downs were recorded for the twelve month periods ending December 31, 2008 and 2007.

17. RELATED PARTY TRANSACTIONS

The following table summarizes the company's related party transactions after eliminations for the year. These transactions are in the normal course of operations and have been carried out on the same terms as would apply with unrelated parties.

($ millions)	**2008**	2007	2006
Operating revenues			
Sales to refining and marketing segment joint ventures:			
Refined products	**368**	329	294
Petrochemicals	**188**	163	136

The company has supply agreements with two refining and marketing segment joint ventures for the sale of refined products. The company also has a supply agreement with a refining and marketing segment joint venture for the sale of petrochemicals.

At December 31, 2008, amounts due from refining and marketing segment joint ventures were $13 million (2007 – $17 million).

Sales to and balances with refining and marketing segment joint ventures are established and agreed to by the various parties and approximate fair value.

18. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

As at December 31 ($ millions)	**2008**	2007
Unrealized foreign currency translation adjustment	**84**	(266)
Unrealized gains and losses on derivative hedging activities	**13**	13
Total	**97**	(253)

19. SUPPLEMENTAL INFORMATION

($ millions)	**2008**	2007	2006
Geographic areas			
Revenues			
Canada	**25 043**	14 365	12 930
U.S.	**4 945**	4 091	3 532
Other	**101**	109	84
	30 089	18 565	16 546
Total assets			
Canada	**29 178**	21 615	16 227
U.S.	**2 840**	2 556	2 439
Other	**510**	338	293
	32 528	24 509	18 959
Export sales [(a)]	**761**	876	810
Exploration expenses			
Geological and geophysical	**29**	26	51
Other	**—**	—	1
Cash costs	**29**	26	52
Dry hole costs	**61**	69	52
Cash and dry hole costs [(b)]	**90**	95	104
Leasehold impairment [(c)]	**—**	—	2
	90	95	106
Taxes other than income taxes			
Excise taxes [(d)]	**570**	568	538
Production, property and other taxes	**109**	80	57
	679	648	595
Allowance for doubtful accounts	**4**	3	4

(a) Sales of crude oil, natural gas and refined products from Canada to customers in the United States and sales of petrochemicals to customers in the United States and Europe.

(b) Included in the Consolidated Statements of Earnings and Comprehensive Income as exploration expenses.

(c) Included in depreciation, depletion and amortization in the Consolidated Statements of Earnings and Comprehensive Income.

(d) Included in operating revenues in the Consolidated Statements of Earnings and Comprehensive Income.

20. DIFFERENCES BETWEEN CANADIAN AND U.S. GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The consolidated financial statements have been prepared in accordance with Canadian GAAP. The application of United States GAAP (U.S. GAAP) would have the following effects on earnings and comprehensive income as reported:

($ millions)	Notes	**2008**	2007	2006
Net earnings as reported, Canadian GAAP		**2 137**	2 983	2 969
Adjustments				
Derivatives and hedging activities	(a)	**—**	—	11
Stock-based compensation expense	(b)	**(7)**	15	(19)
Research and development costs	(g)	**(1)**	(34)	—
Income tax expense		**1**	4	(3)
Net earnings from continuing operations, U.S. GAAP		**2 130**	2 968	2 958
Cumulative effect of change in accounting principles, net of income taxes of $nil (2007 – $nil; 2006 – $2)	(b)	**—**	—	(4)
Net earnings, U.S. GAAP		**2 130**	2 968	2 954
Derivatives and hedging activities, net of income taxes of $nil (2007 – $nil; 2006 – $3)	(a)	**—**	5	6
Minimum pension liability, net of income taxes of $nil (2007 – $nil; 2006 – $20)	(c)	**—**	—	39
Pension and Post-retirement obligation, net of income taxes of $20 (2007 – $8)	(c)	**43**	17	—
Foreign currency translation adjustment		**350**	(195)	10
Comprehensive income, U.S. GAAP		**2 523**	2 795	3 009

Per common share (dollars)	**2008**	2007	2006
Net earnings per share from continuing operations, U.S. GAAP			
Basic	**2.29**	3.22	3.22
Diluted	**2.25**	3.15	3.14
Net earnings per share, U.S. GAAP			
Basic	**2.29**	3.22	3.22
Diluted	**2.25**	3.15	3.14

The application of U.S. GAAP would have the following effects on the consolidated balance sheets as reported:

		December 31, 2008		December 31, 2007	
	Notes	As Reported	U.S. GAAP	As Reported	U.S. GAAP
Current assets		**3 237**	**3 237**	3 160	3 160
Property, plant and equipment, net	(g)	**28 316**	**28 281**	20 945	20 911
Deferred charges and other	(i)	**975**	**1 047**	404	449
Total assets		**35 528**	**32 565**	24 509	24 520
Current liabilities		**3 529**	**3 529**	3 156	3 156
Long-term borrowings	(i)	**7 875**	**7 947**	3 811	3 856
Accrued liabilities and other	(b,c)	**1 986**	**2 094**	1 434	1 602
Future income taxes	(b,c,g)	**4 615**	**4 569**	4 212	4 147
Share capital	(b)	**1 113**	**1 201**	881	944
Contributed surplus	(b)	**288**	**313**	194	240
Retained earnings	(b,g)	**13 025**	**12 894**	11 074	10 950
Accumulated other comprehensive income (loss)	(c)	**97**	**18**	(253)	(375)
Total liabilities and shareholders' equity		**35 528**	**32 565**	24 509	24 520

The application of U.S. GAAP would have no material impact on statements of cash flow as reported.

(a) Derivative Financial Instruments

The adoption of CICA Handbook section 1530 "Comprehensive Income", section 3251 "Equity", section 3855 "Financial Instruments, Recognition and Measurement", and section 3865 "Hedging" on January 1, 2007 substantially aligned Canadian GAAP with U.S. GAAP for the treatment of the company's derivative financial instruments. As a result, there were no differences between Canadian and U.S. GAAP for the years ended December 31, 2008 and December 31, 2007. For comparative balances for the year ended December 31, 2006 disclosed under U.S. GAAP, the company accounted for its derivative financial instruments under the same method as described in note 7.

Under U.S. GAAP, for the year ended December 31, 2006, the company would have recognized $5 million of hedging gains relating to forecasted cash flows in 2007 and 2008. The net earnings impact of this ineffectiveness was recognized for Canadian GAAP purposes on January 1, 2007 as an adjustment to opening retained earnings.

Accumulated Other Comprehensive Earnings (AOCI) and U.S. GAAP Net Earnings Impacts

A reconciliation of changes in AOCI attributable to derivative hedging activities for the years ended December 31 is as follows:

($ millions)	**2008**	2007
AOCI attributable to derivatives and hedging activities, beginning of the period, net of income taxes of $4 (2007 – $4)	**13**	8
Current period net changes arising from cash flow hedges, net of income taxes of $2 (2007 – $1)	**(7)**	8
Net unrealized hedging losses at the beginning of the period reclassified to earnings during the period, net of income taxes of $3 (2007 – $2)	**7**	(3)
AOCI attributable to derivatives and hedging activities, end of period, net of income taxes of $5 (2007 – $4)	**13**	13

For the year ended December 31, 2006, U.S. GAAP net earnings increased by $7 million, net of income taxes of $4 million to reflect the impact of ineffectiveness on derivative contracts classified as cash flow hedges.

(b) Stock-Based Compensation

Following U.S. Financial Accounting Standards Board (FASB) Statement 123(R), "Share-Based Payment", using the modified-prospective approach, the company expenses common share options issued after January 1, 2003 in a manner consistent with Canadian GAAP. The statement requires the recognition of an expense for employee services received in exchange for an award of equity instruments based on the grant date fair value of the award. The cost is to be recognized over the period for which an employee is required to provide the service in exchange for the award. In addition, the statement requires recognition of compensation expense for the portion of outstanding unvested awards granted prior to the effective date.

Under Canadian GAAP, the company's Performance Share Units (PSUs) are measured using an intrinsic approach, a fair-value technique not permitted under U.S. GAAP. For U.S. GAAP, our PSUs have been measured using a Monte Carlo Simulation approach to determine fair value. The impact on net earnings for the year ended December 31, 2008 is an expense of $2 million, net of income taxes of $1 million (2007 – recovery of previously recognized stock-based compensation expense of $17 million expense, net of income taxes of $6 million; 2006 – $3 million expense, net of income taxes of $1 million).

Under Canadian GAAP, compensation expense related to common share options granted prior to January 1, 2003 ("pre-2003 options") is not recognized in the Consolidated Statements of Earnings and Comprehensive Income. FAS 123(R) requires the recognition of expense related to the company's pre-2003 options. This resulted in an increase to stock-based compensation expense of $4 million (2007 – $8 million; 2006 – $15 million). There was no impact on income taxes.

(c) Accounting for Defined Benefit Pension and Other Post-Retirement Plans

On December 31, 2006, the Company adopted FAS 158, "Employers Accounting for Defined Benefit and Other Post Retirement Plans", requiring the recognition of the over funded or under funded status of a defined benefit post-retirement plan as an asset or liability on the balance sheet, with changes to funded status in the year recorded through comprehensive income, net of income taxes. The standard was applied prospectively effective December 31, 2006, as retrospective application was not permitted.

Prior to the adoption of FAS 158, recognition of an additional minimum pension liability was required when the accumulated benefit obligation exceeded the fair value of plan assets to the extent that such excess was greater than accrued pension costs otherwise recorded. For the year ended December 31, 2006, the company would have recognized an increase in other comprehensive income of $39 million, net of income taxes of $20 million. No such adjustment was required under Canadian GAAP.

As required under FAS 158, the minimum pension liability adjustment recorded prior to December 31, 2006 was eliminated upon adoption.

Accumulated Other Comprehensive Income (AOCI) and U.S. GAAP Net Earnings Impacts

($ millions)	**2008**	2007
AOCI attributable to defined benefit pension and other post-retirement plans, beginning of period, net of income taxes of $59 million (2007 – $67 million)	**(122)**	(139)
Amortization of net actuarial loss, net of income taxes of $9 million (2007 – $10 million)	**19**	21
Amortization of past service costs, net of income taxes of $1 million (2007 – $1 million)	**(2)**	(2)
Adjustments to unamortized net actuarial loss, net of income taxes of $12 million (2007 – $2 million)	**26**	(2)
AOCI attributable to defined benefit pension and other post-retirement plans, end of period, net of income taxes of $39 million (2007 – $59 million)	**(79)**	(122)

Total amount included in AOCI expected to be recognized as components of net periodic benefit cost during 2009 are as follows:

Amortization of net actuarial loss	$25 million
Amortization of past service costs	$(3) million

(d) Cumulative Foreign Currency Translation

Prior to the adoption of CICA Section 1530 "Comprehensive Income" on January 1, 2007, under Canadian GAAP, foreign currency gains and losses arising on translation of the company's U.S. based foreign operations were recorded directly to shareholders' equity. Under the new Canadian standard, these foreign currency translation gains and losses are treated as they have been under U.S. GAAP, and included as a component of comprehensive income.

(e) Suspended Exploratory Well Costs

Under U.S. GAAP, the company is permitted to continue the capitalization of exploratory well costs beyond one year if (a) the well found a sufficient quantity of reserves to justify its completion as a producing well and (b) the entity is making sufficient progress assessing the reserves and the economic and operating viability of the project.

The table below provides details of the changes in the balance of suspended exploratory well costs as well as an aging summary of those costs.

Change in capitalized suspended exploratory well costs

($ millions)	**2008**	2007	2006
Balance, beginning of year	**21**	23	15
Additions pending determination of proved reserves	**35**	14	21
Charged to dry hole expense	**(15)**	(6)	—
Reclassifications to proved properties	**—**	(10)	(13)
Balance, end of year	**41**	21	23
Capitalized for a period greater than one year ($ millions)	**6**	7	2
Number of projects that have exploratory well costs capitalized for a period greater than 12 months	**2**	3	3

(f) Accounting for Purchases and Sales Inventory with the Same Counterparty

Emerging Issues Task Force (EITF) Abstract No. 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty" addresses when it is appropriate to measure purchases and sales of inventory with the same counterparty at fair value and record them in revenues and cost of sales and when they should be recorded as exchanges measured at the book value of the item sold. The EITF concluded that purchases and sales of inventory with the same counterparty that are entered into in contemplation of one another should be combined and recorded as exchanges measured at the book value of the item sold (reported net versus gross). The EITF is effective for transactions entered into subsequent to April 1, 2006.

As required by EITF 04-13, we record certain crude oil, natural gas, petroleum product and chemical purchases and sales entered into contemporaneously with the same counterparty on a net basis within the "purchases of crude oil and products" line in the Consolidated Statements of Earnings and Comprehensive Income. These transactions are undertaken to ensure that the appropriate crude oil is at the appropriate refineries when required and that the appropriate products are available to meet customer demands. These transactions take place in the oil sands and refining and marketing operating segments.

In addition, until 2006, the refining and marketing segment sold finished product and bought coker gas oil as a raw material to be used in the refining process from the same counterparty under terms specified in a single contract. These sales and purchases, as noted in the table below, were recorded at fair value in "revenue" and "purchases of crude oil and products" in the Consolidated Statements of Earnings and Comprehensive Income in accordance with the consensus for Issue 2 in EITF 04-13.

The purchase/sale of contract amounts included in revenue for 2008, 2007 and 2006 are shown below.

($ millions)	**2008**	2007	2006
Consolidated revenues	**30 089**	18 565	16 546
Amounts included in revenues for purchase/sale contracts with the same counterparty [1]	**—**	—	5

(1) Associated costs are in "purchases of crude oil and products".

(g) Research and Development Costs

Under Canadian GAAP, development expenditures are eligible to be capitalized when specific criteria are met. Under FAS 2, "Accounting for Research and Development Costs", development costs are required to be charged to expense when incurred. As a result, $1 million would have been charged to income during 2008 (2007 – $24 million, net of income taxes of $10 million; 2006 – nil).

(h) Accounting for Uncertainties in Income Taxes

Effective January 1, 2007, the company adopted the FASB Interpretation No. 48 "Accounting for Uncertainty in Income Taxes" (FIN 48). FIN 48 is an interpretation of FASB Statement 109 "Accounting for Income Taxes" and outlines the recognition and related disclosure requirements of uncertain tax positions determined to be more likely than not, defined as greater than 50%, to be sustained on audit.

The adoption of FIN 48 had no impact on net earnings or financial position.

(i) Deferred Financing Costs

Effective January 1, 2007, under Canadian GAAP, deferred financing costs on long-term debt are included in the carrying value of the related debt. Under U.S. GAAP, these costs are recorded as a deferred charge. As a result, $72 million would have been reclassified from long-term debt to deferred charges and other at December 31, 2008 (December 31, 2007 – $45 million).

(j) Inventory

Effective January 1, 2008, the company retroactively adopt a FIFO (first-in, first-out) based valuation approach for inventory under Canadian GAAP. We have retroactively adopted the same FIFO valuation approach for U.S. GAAP. As such, there continues to be no impact to net earnings or financial position.

Recently Adopted Accounting Standards

Effective January 1, 2008, the company adopted FAS 157 "Fair Value Measurements" and FAS 159 "The Fair Value Option for Financial Assets and Financial Liabilities". Retrospective application was not permitted. The adoption of these standards had no impact on net earnings or financial position.

Recently Issued Accounting Standards

In December 2007, FASB issued FAS 141(revised), "Business Combinations". The standard, effective January 1, 2009, establishes principles and requirements of the acquisition method for business combinations and the related disclosures. The revisions are to be applied with prospective application, where early adoption is prohibited. No impact to net earnings or financial position is anticipated.

In December 2007, FASB issued FAS 160, "Non-Controlling Interests in Consolidated Financial Statements". The standard is effective January 1, 2009. This interpretation of ARB No. 51 outlines that a non-controlling interest in a subsidiary represents an interest in the consolidated entity, which should be reported as equity in the financial statements. The new standard is to be applied with prospective application, where early adoption is prohibited. No impact to net earnings or financial position is anticipated.

QUARTERLY SUMMARY (unaudited)

FINANCIAL DATA

($ millions, except per share amounts)	For the Quarter Ended Mar 31 2008	June 30 2008	Sept 30 2008	Dec 31 2008	Total Year 2008	For the Quarter Ended Mar 31 2007	June 30 2007	Sept 30 2007	Dec 31 2007	Total Year 2007
Revenues	**5 988**	**7 959**	**8 946**	**7 196**	**30 089**	4 053	4 525	4 802	5 185	18 565
Net earnings (loss)										
Oil Sands	**695**	**751**	**854**	**575**	**2 875**	468	476	494	1 036	2 474
Natural Gas	**19**	**52**	**18**	**—**	**89**	4	(4)	—	25	25
Refining and Marketing	**95**	**91**	**46**	**(181)**	**51**	106	238	69	31	444
Corporate and eliminations	**(101)**	**(65)**	**(103)**	**(609)**	**(878)**	(2)	28	64	(50)	40
	708	**829**	**815**	**(215)**	**2 137**	576	738	627	1 042	2 983
Per common share										
Net earnings (loss) attributable to common shareholders										
– basic	**0.77**	**0.89**	**0.87**	**(0.24)**	**2.29**	0.63	0.80	0.68	1.12	3.23
– diluted	**0.75**	**0.87**	**0.86**	**(0.24)**	**2.26**	0.61	0.78	0.66	1.10	3.17
Cash dividends	**0.05**	**0.05**	**0.05**	**0.05**	**0.20**	0.04	0.05	0.05	0.05	0.19
Cash flow from (used in) operations										
Oil Sands	**910**	**1 174**	**1 109**	**645**	**3 838**	600	657	829	1 057	3 143
Natural Gas	**82**	**119**	**103**	**64**	**368**	64	70	47	67	248
Refining and Marketing	**190**	**210**	**85**	**(207)**	**278**	180	342	126	68	716
Corporate and eliminations	**(21)**	**(98)**	**49**	**49**	**(21)**	(19)	(42)	(45)	8	(98)
	1 161	**1 405**	**1 346**	**551**	**4 463**	825	1 027	957	1 200	4 009

OPERATING DATA

OIL SANDS

(thousands of barrels per day)

	Mar 31 2008	June 30 2008	Sept 30 2008	Dec 31 2008	Total Year 2008	Mar 31 2007	June 30 2007	Sept 30 2007	Dec 31 2007	Total Year 2007
Production (1)										
Total production	**248.0**	**174.6**	**245.6**	**243.8**	**228.0**	248.2	202.3	239.1	252.5	235.6
Firebag	**34.6**	**34.7**	**40.4**	**39.7**	**37.4**	35.3	36.2	35.8	40.4	36.9
Sales										
Light sweet crude oil	**96.2**	**68.2**	**48.1**	**95.7**	**77.0**	105.5	100.0	99.3	102.2	101.7
Diesel	**28.0**	**21.2**	**10.9**	**19.1**	**19.8**	29.5	20.3	23.9	26.0	25.0
Light sour crude oil	**120.8**	**91.8**	**157.4**	**144.2**	**128.7**	112.7	84.2	94.1	118.2	102.3
Bitumen	**0.1**	**0.3**	**2.6**	**3.1**	**1.5**	6.8	3.8	6.6	5.4	5.7
Total sales	**245.1**	**181.5**	**219.0**	**262.1**	**227.0**	254.5	208.3	223.9	251.8	234.7

QUARTERLY SUMMARY (unaudited) (continued)

OPERATING DATA (continued)

($ millions, except per share amounts)	For the Quarter Ended Mar 31 2008	June 30 2008	Sept 30 2008	Dec 31 2008	Total Year 2008	For the Quarter Ended Mar 31 2007	June 30 2007	Sept 30 2007	Dec 31 2007	Total Year 2007
OIL SANDS (continued)										
Average sales price (2) (dollars per barrel)										
Light sweet crude oil	**100.93**	**122.12**	**121.96**	**64.58**	**97.54**	68.63	75.64	81.00	87.34	78.03
Other (diesel, light sour crude oil and bitumen)	**93.09**	**120.52**	**114.74**	**59.77**	**95.15**	63.62	66.74	73.76	78.48	70.86
Total	**96.16**	**121.12**	**116.32**	**61.53**	**95.96**	65.70	71.01	76.97	82.07	74.01
Total (a)	**96.22**	**122.39**	**117.14**	**61.20**	**96.33**	65.61	71.01	76.97	82.36	74.07
Cash operating costs and total operating costs – Total Operations (dollars per barrel sold rounded to the nearest $0.05)										
Cash costs	**25.10**	**40.10**	**27.80**	**35.35**	**31.45**	21.75	28.40	23.00	24.10	24.15
Natural gas	**5.00**	**8.75**	**4.30**	**4.05**	**5.25**	4.50	4.20	2.10	3.60	3.55
Imported bitumen	**1.45**	**2.00**	**1.90**	**1.90**	**1.80**	0.05	0.10	—	0.20	0.10
Cash operating costs (3)	**31.55**	**50.85**	**34.00**	**41.30**	**38.50**	26.30	32.70	25.10	27.90	27.80
Project start-up costs	**0.30**	**0.90**	**0.35**	**0.30**	**0.40**	0.10	1.15	1.10	0.55	0.95
Total cash operating costs (4)	**31.85**	**51.75**	**34.35**	**41.60**	**38.90**	26.40	33.85	26.20	28.45	28.75
Depreciation, depletion and amortization	**5.75**	**8.30**	**6.70**	**7.50**	**6.95**	4.45	5.85	5.70	5.60	5.40
Total operating costs (5)	**37.60**	**60.05**	**41.05**	**49.10**	**45.85**	30.85	39.70	31.90	34.05	34.15
Cash operating costs and total operating costs – In-situ Bitumen Production Only (dollars per barrel sold rounded to the nearest $0.05)										
Cash costs	**14.60**	**10.10**	**10.75**	**16.55**	**13.00**	11.05	10.60	11.85	9.95	10.85
Natural gas	**14.10**	**14.55**	**11.30**	**9.65**	**12.30**	11.05	10.60	9.10	9.15	9.90
Cash operating costs (6)	**28.70**	**24.65**	**22.05**	**26.20**	**25.30**	22.10	21.20	20.95	19.10	20.75
Firebag start-up costs	**0.35**	**1.65**	**0.80**	**—**	**0.65**	—	—	—	—	—
Total cash operating costs (7)	**29.05**	**26.30**	**22.85**	**26.20**	**25.95**	22.10	21.20	20.95	19.10	20.75
Depreciation, depletion and amortization	**6.75**	**6.70**	**5.40**	**6.55**	**6.35**	5.35	5.75	6.70	6.80	6.20
Total operating costs (8)	**35.80**	**33.00**	**28.25**	**32.75**	**32.30**	27.45	26.95	27.65	25.90	26.95

QUARTERLY SUMMARY (unaudited) (continued)

OPERATING DATA (continued)

($ millions, except per share amounts)	For the Quarter Ended Mar 31 2008	June 30 2008	Sept 30 2008	Dec 31 2008	Total Year 2008	For the Quarter Ended Mar 31 2007	June 30 2007	Sept 30 2007	Dec 31 2007	Total Year 2007
NATURAL GAS										
Gross production (b)										
— Natural gas (millions of cubic feet per day)	**209**	**205**	**197**	**195**	**202**	191	191	193	210	196
— Natural gas liquids and crude oil (thousands of barrels per day)	**3.3**	**3.4**	**2.6**	**3.1**	**3.1**	3.1	3.0	3.1	3.2	3.1
— Total gross production (thousands of barrels of oil equivalent per day)	**38.2**	**37.7**	**35.4**	**35.6**	**36.7**	34.9	34.9	35.2	38.2	35.8
— Total gross production (millions of cubic feet equivalent per day)	**229**	**226**	**213**	**213**	**220**	209	209	211	229	215
Average sales price (2)										
— Natural gas (dollars per thousand cubic feet)	**7.30**	**9.62**	**9.10**	**6.90**	**8.23**	7.01	6.85	5.39	6.08	6.32
— Natural gas(a) (dollars per thousand cubic feet)	**7.31**	**9.68**	**9.14**	**6.84**	**8.25**	7.14	6.83	5.14	6.02	6.27
— Natural gas liquids and crude oil – conventional (dollars per barrel)	**64.14**	**86.14**	**96.88**	**39.31**	**70.89**	56.69	51.21	58.11	60.31	56.64
REFINING AND MARKETING										
Refined product sales (thousands of cubic metres per day)	**30.5**	**33.1**	**32.0**	**31.5**	**31.5**	31.6	34.6	35.1	32.8	33.5
Utilization of refining capacity (%)	**90**	**102**	**99**	**98**	**97**	97	108	102	87	98

(a) Excludes the impact of hedging activities.

(b) Currently Natural Gas production is located in the Western Canada Sedimentary Basin.

Definitions

(1) Total operations production – Total operations production includes total production from both mining and in-situ operations.

(2) Average sales price – This operating statistic is calculated before royalties and net of related transportation costs (including or excluding the impact of hedging activities as noted).

(3) Cash operating costs – Total operations – Include cash costs that are defined as operating, selling and general expenses (excluding inventory changes), accretion expense, taxes other than income taxes and the cost of bitumen imported from third parties. Per barrel amounts are based on total production volumes. For a reconciliation of this non GAAP financial measure see Management's Discussion and Analysis.

(4) Total cash operating costs – Total operations – Include cash operating costs – Total operations as defined above and cash start-up costs. Per barrel amounts are based on total production volumes.

(5) Total operating costs – Total operations – Include total cash operating costs – Total operations as defined above and non-cash operating costs. Per barrel amounts are based on total production volumes.

(6) Cash operating costs – In-situ bitumen production – Include cash costs that are defined as operating, selling and general expenses (excluding inventory changes), accretion expense and taxes other than income taxes. Per barrel amounts are based on in-situ production volumes only.

(7) Total cash operating costs – In-situ bitumen production – Include cash operating costs – In-situ bitumen production as defined above and cash start-up costs for in-situ operations. Per barrel amounts are based on in-situ production volumes only.

(8) Total operating costs – In-situ bitumen production – Include total cash operating costs – In-situ bitumen production as defined above and non-cash operating costs. Per barrel amounts are based on in-situ production volumes only.

Metric conversion

Crude oil, refined products, etc. – $1m^3$ (cubic metre) = approximately 6.29 barrels
Natural gas – $1m^3$ (cubic metre) = approximately 35.49 cubic feet

FIVE-YEAR FINANCIAL SUMMARY (unaudited)

($ millions, except for ratios)	**2008**	2007	2006	2005	2004
Revenues					
Oil Sands	**9 386**	6 775	7 407	3 965	3 640
Natural Gas	**754**	553	578	679	567
Refining and Marketing	**21 371**	11 805	9 310	7 636	5 317
Corporate and eliminations	**(1 422)**	(568)	(749)	(499)	(497)
	30 089	18 565	16 546	11 781	9 027
Net earnings (loss)					
Oil Sands	**2 875**	2 474	2 775	986	957
Natural Gas	**89**	25	106	155	114
Refining and Marketing	**51**	444	244	237	138
Corporate and eliminations	**(878)**	40	(156)	(124)	(105)
	2 137	2 983	2 969	1 254	1 104
Cash flow from (used in) operations					
Oil Sands	**3 838**	3 143	3 903	1 961	1 718
Natural Gas	**368**	248	281	412	314
Refining and Marketing	**278**	716	451	463	251
Corporate and eliminations	**(21)**	(98)	(111)	(209)	(228)
	4 463	4 009	4 524	2 627	2 055
Capital and exploration expenditures					
Oil Sands	**7 051**	4 431	2 463	1 948	1 119
Natural Gas	**339**	531	458	363	279
Refining and Marketing	**172**	376	665	779	418
Corporate	**28**	77	27	63	31
	7 590	5 415	3 613	3 153	1 847
Total assets	**32 528**	24 509	18 959	15 335	11 807
Ending capital employed[(a)]					
Short-term and long-term debt, less cash and cash equivalents	**7 226**	3 248	1 849	2 868	2 109
Shareholders' equity	**14 523**	11 896	9 084	6 130	4 912
	21 749	15 144	10 933	8 998	7 021
Less capitalized costs related to major projects in progress	**(6 583)**	(4 148)	(2 649)	(2 938)	(1 467)
	15 166	10 996	8 284	6 060	5 554
Total Suncor employees (number at year-end)	**6 798**	6 465	5 766	5 152	4 605

FIVE-YEAR FINANCIAL SUMMARY (unaudited) (continued)

($ millions, except for ratios)	**2008**	2007	2006	2005	2004
Dollars per common share					
Net earnings attributable to common shareholders	**2.29**	3.23	3.23	1.37	1.22
Cash dividends	**0.20**	0.19	0.15	0.12	0.115
Cash flow from operations	**4.79**	4.35	4.93	2.88	2.27
Ratios					
Return on capital employed (%) [(a), (b)]	**22.5**	29.3	40.0	21.2	19.4
Return on capital employed (%) [(c)]	**16.3**	21.5	30.1	15.4	16.4
Return on shareholders' equity (%) [(d)]	**16.2**	28.4	39.0	22.7	25.1
Debt to debt plus shareholders' equity (%) [(e)]	**35.2**	24.3	20.7	33.1	30.9
Net debt to cash flow from operations (times) [(f)]	**1.6**	0.8	0.4	1.1	1.0
Interest coverage – cash flow basis (times) [(g)]	**14.1**	23.2	30.4	17.9	14.9
Interest coverage – net earnings basis (times) [(h)]	**8.9**	18.8	25.5	13.5	11.7

(a) Capital employed – the sum of shareholders' equity plus short-term debt and long-term debt less cash and cash equivalents, less capitalized costs related to major projects in progress (as applicable).

(b) Net earnings adjusted for after-tax financing expenses (income) for the twelve month period ended; divided by average capital employed. 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 average capitalized costs related to major projects in progress (as applicable). Return on capital employed (ROCE) for Suncor operating segments presented in the Quarterly Operating Summary is calculated in a manner consistent with consolidated ROCE. For a detailed annual reconciliation of this non-GAAP financial measure see page 40 of MD&A.

(c) 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.

(d) Net earnings as a percentage of average shareholders' equity. Average shareholders' equity is the sum of total shareholders' equity at the beginning and end of the year divided by two.

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

(f) Short-term debt plus long-term debt less cash and cash equivalents; divided by cash flow from operations for the year then ended.

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

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

SUPPLEMENTAL FINANCIAL AND OPERATING INFORMATION (unaudited)

	2008	2007	2006	2005	2004
OIL SANDS					
Production (thousands of barrels per day)	**228.0**	235.6	260.0	171.3	226.5
Sales (thousands of barrels per day)					
Light sweet crude oil	**77.0**	101.7	110.5	73.3	114.9
Diesel	**19.8**	25.0	28.2	15.6	27.9
Light sour crude oil	**128.7**	102.3	118.2	59.8	75.1
Bitumen	**1.5**	5.7	6.2	16.6	8.4
	227.0	234.7	263.1	165.3	226.3
Average sales price (dollars per barrel)					
Light sweet crude oil	**97.54**	78.03	71.98	49.93	45.60
Other (diesel, light sour crude oil and bitumen)	**95.15**	70.86	65.17	56.90	39.13
Total	**95.96**	74.01	68.03	53.81	42.28
Total (a)	**96.33**	74.07	68.03	62.68	49.78
Cash operating costs – total operations (b)	**38.50**	27.80	21.70	24.55	15.15
Total cash operating costs – total operations (b)	**38.90**	28.75	22.10	24.65	15.45
Total operating costs – total operations (b)	**45.85**	34.15	26.15	29.95	19.05
Cash operating costs – In-situ bitumen production (b), (e)	**25.30**	20.75	17.30	22.20	22.05
Total cash operating costs – In-situ bitumen production (b), (e)	**25.95**	20.75	19.00	23.20	28.90
Total operating costs – In-situ bitumen production (b), (e)	**32.30**	26.95	24.55	28.10	34.90
Ending capital employed excluding major projects in progress	**9 352**	6 605	5 039	4 468	4 091
Return on capital employed (%) (c)	**35.5**	43.0	53.1	23.0	22.3
Return on capital employed (%) (d)	**21.8**	27.9	39.8	16.5	18.3

(a) Excludes the impact of hedging activities.

(b) Dollars per barrel rounded to the nearest $0.05. See definitions on page 89.

(c) See definitions on page 91.

(d) 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.

(e) In-situ bitumen production commenced commercial operations on April 1, 2004.

	2008	2007	2006	2005	2004
NATURAL GAS					
Production					
Natural gas (millions of cubic feet per day)					
Gross	**202**	196	191	190	200
Net [(a)]	**154**	153	141	137	147
Natural gas liquids and crude oil (thousands of barrels per day)					
Gross	**3.1**	3.1	3.0	3.2	3.5
Net [(a)]	**2.3**	2.4	2.3	2.6	2.6
Total (thousands of boe [(b)] per day)					
Gross	**36.7**	35.8	34.8	34.8	36.8
Net [(a)]	**28.0**	27.9	25.8	25.3	27.1
Total (millions of cubic feet equivalent per day)					
Gross	**220**	215	209	209	221
Net [(a)]	**168**	167	155	152	163
Average sales price					
Natural gas (dollars per thousand cubic feet)	**8.23**	6.32	7.15	8.57	6.70
Natural gas (dollars per thousand cubic feet) [(c)]	**8.25**	6.27	6.95	8.59	6.73
Natural gas liquids and crude oil – conventional (dollars per barrel)	**70.89**	56.64	51.93	54.24	44.99
Ending capital employed	**1 152**	1 153	857	562	447
Return on capital employed (%) [(g)]	**7.7**	2.5	14.9	30.7	26.9
Undeveloped landholdings [(d)]					
Oil and gas (millions of acres)					
Western Canada					
Gross	**1.8**	1.3	1.2	0.6	0.7
Net [(e)]	**0.9**	0.7	0.7	0.4	0.5
International					
Gross	**0.1**	0.1	0.1	0.4	0.7
Net [(e)]	**—**	—	—	0.2	0.4
Net wells drilled [(f)]					
Exploratory					
Oil	**—**	—	—	—	—
Gas	**6**	7	3	8	5
Dry	**4**	6	5	4	5
Development					
Oil	**—**	1	1	1	—
Gas	**18**	14	13	18	16
Dry	**5**	3	4	3	—
	33	31	26	34	26

(a) Net of royalties
(b) Barrel of oil equivalent – converts natural gas to oil on the approximate energy equivalent basis that 6,000 cubic feet equals one barrel of oil.
(c) Excludes the impact of hedging activities.
(d) Metric conversion: Landholdings – 1 hectare = approximately 2.5 acres
(e) Our interest in the undeveloped landholdings
(f) Excludes interests in 4 net exploratory wells and 6 net development wells in progress at the end of 2008.
(g) See definitions on page 91.

	2008	2007	2006	2005	2004
REFINING AND MARKETING					
Refined product sales					
(thousands of cubic metres per day)					
Transportation fuels					
Gasoline					
Retail [(a)]	**4.6**	5.2	5.3	5.2	5.3
Other	**11.3**	11.6	10.6	10.1	7.9
Distillate	**10.8**	10.6	8.5	8.3	6.7
Total transportation fuel sales	**26.7**	27.4	24.4	23.6	19.9
Petrochemicals	**0.8**	0.9	0.9	0.7	0.8
Asphalt	**1.8**	1.7	1.2	1.6	1.5
Other	**2.2**	3.5	3.0	3.0	2.5
Total refined product sales	**31.5**	33.5	29.5	28.9	24.7
Crude oil supply and refining					
Processed at refineries					
(thousands of cubic metres per day)	**24.7**	25.1	21.7	22.7	19.9
Utilization of refining capacity (%)	**97**	98	85	97	96
Ending capital employed excluding major projects in progress	**3 220**	2 489	1 938	907	784
Return on capital employed (%) [(b)]	**1.7**	20.0	19.3	27.5	16.2
Return on capital employed (%) [(b), (c)]	**1.7**	17.4	12.2	17.6	14.9
Retail outlets [(d)] (number at year-end)	**427**	419	417	417	421

(a) Excludes sales through joint venture interests.

(b) See definitions on page 91.

(c) 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.

(d) Sunoco-branded and Phillips 66-branded service stations, other private brands managed by refining and marketing, and refining and marketing's interest in service stations managed through joint ventures.

SHARE TRADING INFORMATION (unaudited)

Common shares are listed on the Toronto Stock Exchange and New York Stock Exchange under the symbol SU.

	For the Quarter Ended				For the Quarter Ended			
	Mar 31 2008	**June 30 2008**	**Sept 30 2008**	**Dec 31 2008**	Mar 31 2007	June 30 2007	Sept 30 2007	Dec 31 2007
Share ownership								
Average number outstanding, weighted monthly (thousands)[(a)]	**926 216**	**928 572**	**930 393**	**931 524**	920 148	920 844	921 578	922 374
Share price (dollars)								
Toronto Stock Exchange								
High	**56.14**	**73.10**	**62.37**	**43.78**	46.43	49.85	50.78	54.74
Low	**40.92**	**47.78**	**39.61**	**18.80**	39.83	43.79	44.36	45.63
Close	**49.61**	**59.20**	**44.00**	**23.72**	43.93	47.98	47.23	53.96
New York Stock Exchange – US$								
High	**56.73**	**74.28**	**61.99**	**41.12**	38.90	46.76	50.06	58.99
Low	**39.67**	**46.31**	**38.00**	**14.52**	33.89	37.86	41.19	45.70
Close	**52.61**	**68.56**	**51.64**	**19.50**	38.18	44.96	47.41	54.37
Shares traded (thousands)								
Toronto Stock Exchange	**219 093**	**226 392**	**266 381**	**396 680**	218 970	175 568	199 402	200 466
New York Stock Exchange	**342 938**	**371 303**	**458 534**	**720 851**	355 471	290 564	321 810	300 176
Per common share information (dollars)								
Net earnings attributable to common shareholders	**0.77**	**0.89**	**0.87**	**(0.24)**	0.63	0.80	0.68	1.12
Cash dividends	**0.05**	**0.05**	**0.05**	**0.05**	0.04	0.05	0.05	0.05

(a) The company had approximately 2,971 holders of record of common shares as at January 31, 2008.

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

Information for Security Holders Outside Canada

Cash dividends paid to shareholders resident in countries with which Canada has an income tax convention are usually subject to Canadian non-resident withholding tax of 15%. The withholding tax rate is reduced to 5% on dividends paid to a corporation if it is a resident of the United States that owns at least 10% of the voting shares of the company.

INVESTOR INFORMATION

Stock Trading Symbols and Exchange Listing
Common shares are listed on the Toronto Stock Exchange (TSX) and New York Stock Exchange (NYSE) under the symbol SU.

Dividends
Suncor's Board of Directors reviews its dividend policy quarterly. In 2008, Suncor paid an aggregate dividend of $0.20 per common share.

Dividend Reinvestment and Common Share Purchase Plan
Suncor's Dividend Reinvestment and Common Share Purchase Plan enables shareholders to invest cash dividends in common shares or acquire additional shares through cash payments without payment of brokerage commissions, service charges or other costs associated with administration of the plan. To obtain additional information, call Computershare Trust Company of Canada at 1-877-982-8760. Information regarding the purchase plan is also available in the dividend information section of our website at www.suncor.com/dividends.

Stock Transfer Agent and Registrar
In Canada, Suncor's agent is Computershare Trust Company of Canada. In the United States, Suncor's agent is Computershare Trust Company, Inc.

Independent Auditors
PricewaterhouseCoopers LLP

Independent Reserve Evaluators
GLJ Petroleum Consultants Ltd.

Annual Meeting
Suncor's Annual General Meeting of shareholders will be held at 10:30 a.m. MT on April 23, 2009, at the Metropolitan Conference Centre, 333 Fourth Avenue S.W., Calgary, Alberta. Presentations from the meeting will be webcast live at www.suncor.com/webcasts.

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For further information, to subscribe or cancel duplicate mailings
In addition to Annual and Quarterly Reports, Suncor publishes a biennial Report on Sustainability. All Suncor publications, as well as updates on company news as it happens, are available on our website at www.suncor.com. To receive Suncor news as it happens, subscribe to E-news, which can be found on our website. To order copies of Suncor's print materials call 1-800-558-9071.

If you do not receive our Annual or Quarterly Reports, but would like to receive these reports, call Computershare Trust Company of Canada at 1-877-982-8760 or visit their website at www.computershare.com. Computershare will update your account information accordingly.

Shareholders can help reduce mailing costs and paper waste by electing to receive Suncor's Annual Report and other documents electronically. To register for electronic delivery, registered shareholders should visit www.computershare.com.

GOVERNANCE AND DIRECTOR INFORMATION

Corporate Governance

Providing strategic guidance to the company, setting policy direction and ensuring Suncor is fairly reporting its progress are central to the work of Suncor's Board of Directors. The Board's oversight role encompasses Suncor's strategic planning process, risk management, standards of business conduct and communication with investors and other stakeholders. Suncor's Board is also responsible for selecting, monitoring and evaluating executive leadership and aligning management's decision making with long-term shareholder interest.

A comprehensive description of Suncor's governance practices, including a summary of any differences from those prescribed by the NYSE, is available in the company's Management Proxy Circular on Suncor's website at www.suncor.com/financialreporting or by calling 1-800-558-9071.

Mel E. Benson(3), (4)
(independent)
Calgary, Alberta
Director since 2000
Mel Benson is president of Mel E. Benson Management Services Inc., an international management consulting firm based in Calgary, Alberta. In 2000, Mr. Benson retired from a major international oil company. Mr. Benson is a director of Tenax Energy Inc., Tarpon Energy Services, and the Fort McKay Group of Companies. He is also chair of Winalta Homes Inc. He is active with several charitable organizations including Hull Family Services. He is also a member of the Board of Governors for the Northern Alberta Institute of Technology.

Brian A. Canfield(1), (2)
(independent)
Point Roberts, Washington
Director since 1995
Brian Canfield is the chairman of TELUS Corporation, a telecommunications company. Mr. Canfield is a member of the Order of Canada, a member of the Order of British Columbia and a fellow of the Institute of Corporate Directors.

Bryan P. Davies(3), (4)
(independent)
Toronto, Ontario
Director 1991 to 1996 and since 2000
Bryan Davies is chairman of the Canada Deposit Insurance Corporation. He is also a director of the General Insurance Statistical Agency and is past superintendent of the Financial Services Commission of Ontario. Previously, he was senior vice president, regulatory affairs with the Royal Bank Financial Group. Mr. Davies is also active with a number of not-for-profit charitable organizations.

Brian A. Felesky(1), (4)
(independent)
Calgary, Alberta
Director since 2002
Brian Felesky is counsel to the law firm of Felesky Flynn LLP in Calgary, Alberta. Mr. Felesky also serves as a director on the board and is chair of the audit committee of EPCOR Power LP. He is also a member of the board of Precision Drilling Trust and Resin Systems Inc. and various private corporations. Mr. Felesky is co-chair of Homefront on Domestic Violence, vice chair of the Canada West Foundation, member of the senate of Athol Murray College of Notre Dame, board member of the Calgary Stampede Foundation and a council member of the Alberta Order of Excellence. Mr. Felesky is a Queen's Counsel and member of the Order of Canada.

John T. Ferguson(2), (3)
(independent)
Edmonton, Alberta
Director since 1995
John Ferguson is founder and chairman of the board of Princeton Developments Ltd. and Princeton Ventures Ltd. Mr. Ferguson is also a director of Fountain Tire Ltd., the Royal Bank of Canada and Strategy Summit Ltd. In addition, he is a director of the C.D. Howe Institute and the Alberta Bone and Joint Institute, an advisory member of the Canadian Institute for Advanced Research and chancellor emeritus and chairman emeritus of the University of Alberta. Mr. Ferguson is also a fellow of the Alberta Institute of Chartered Accountants and of the Institute of Corporate Directors.

W. Douglas Ford[1], [2]
(independent)
Bonita Springs, Florida
Director since 2004
W. Douglas Ford was chief executive, refining and marketing for BP p.l.c. from 1998 to 2002 and was responsible for the refining, marketing and transportation network of BP as well as the aviation fuels business, the marine business and BP shipping. Mr. Ford currently serves as a director of USG Corporation and Air Products and Chemicals Inc. He is also a member of the board of trustees of the University of Notre Dame.

Richard L. George
(non-independent, management)
Calgary, Alberta
Director since 1991
Richard George is the president and chief executive officer of Suncor Energy Inc. Mr. George is also a director of the Swiss offshore and onshore drilling company Transocean. In 2006, he was selected to serve as a member of the North American Competitiveness Council. In 2007, he became a member of the Calgary Committee to End Homelessness and he chaired the 2008 Governor General's Canadian Leadership Conference. Mr. George was named a member of the Order of Canada in 2007.

John R. Huff[2], [3]
(independent)
Houston, Texas
Director since 1998
John Huff is chairman of Oceaneering International Inc., an oil field services company. He also serves as director of BJ Services Company, KBR Inc. and Rowan Companies Inc. Mr. Huff is a member of the National Petroleum Council, a trustee of the Houston Museum of Natural Science and is a director of St. Luke's Episcopal Hospital System in Houston.

M. Ann McCaig[3], [4]
(independent)
Calgary, Alberta
Director since 1995
Mrs. McCaig is a trustee of the $400 million Killam Estate, a director of the Gairdner Foundation, the Chair of the Calgary Health Trust and the Chair of the Alberta Adolescent Recovery Centre, as well as the Honorary Chair of the Alberta Bone and Joint Institute. She is a director of the Calgary Stampede Foundation. She is Chancellor Emeritus at the University of Calgary having served as Chancellor from 1994 to 1998. Mrs. McCaig has received numerous awards including an Honorary Doctor of Laws Degree from the University of Calgary and the University of Alberta, the University of Saskatchewan Alumni Humanitarian Award, the Queen Elizabeth Award, the 125th Confederation of Canada Award and the Alberta Order of Excellence. She is also a Member of the Order of Canada.

Michael W. O'Brien[1], [2]
(independent)
Canmore, Alberta
Director since 2002
Michael O'Brien served as executive vice president, corporate development, and chief financial officer of Suncor Energy Inc. before retiring in 2002. Mr. O'Brien serves on the board of Shaw Communications Inc. and is an advisor to CRA International. In addition, he is past chair of the board of trustees for Nature Conservancy Canada, past chair of the Canadian Petroleum Products Institute and past chair of Canada's Voluntary Challenge for Global Climate Change.

Eira M. Thomas[1], [4]
(independent)
West Vancouver, British Columbia
Director since 2006
Eira Thomas assumed the role of executive chairman of Stornoway Diamond Corporation, a mineral exploration company, on January 1, 2009 after serving as chief executive officer since July 2003. Previously, Ms. Thomas was president of Navigator Exploration Corporation and chief executive officer of Stornoway Ventures Ltd. She is also a director of Strongbow Exploration Inc. and Fortress Minerals Corp. In addition, Ms. Thomas is a director of the University of Toronto (U of T) Alumni Association, Lassonde Advisory Board of the U of T, Prospectors and Developers Association of Canada and the Northwest Territories and Nunavut Chamber of Mines. She also is a member of the U of T President's Internal Advisory Council.

(1) Audit Committee
(2) Governance Committee
(3) Human Resources and Compensation Committee
(4) Environment, Health & Safety Committee

CORPORATE OFFICERS[1], [2]

Richard L. George
President and Chief Executive Officer

J. Kenneth Alley
Senior Vice President and
Chief Financial Officer

Marlowe Allison
Vice President and Treasurer

Kirk Bailey
Executive Vice President,
Oil Sands

Joel Croteau
Senior Vice President,
Natural Gas and In-Situ Resources

Bart Demosky
Senior Vice President,
Business Services

Terrence J. Hopwood
Senior Vice President and General Counsel

Sue Lee
Senior Vice President,
Human Resources and Communications

Mark Little
Senior Vice President,
Strategic Growth and Energy Trading

Kevin D. Nabholz
Executive Vice President,
Major Projects

Janice B. Odegaard
Vice President and Corporate Secretary

Jay Thornton
Executive Vice President,
Refining and Marketing

Steven W. Williams
Chief Operating Officer

(1) Offices shown are positions held by the officers in relation to businesses of Suncor Energy Inc. and its subsidiaries. On a legal entity basis, Mr. Little is president of Suncor Energy Marketing Inc. and Mr. Thornton is president of Suncor Energy Products Inc., each of which are Suncor's Canada-based downstream subsidiaries; and Mr. Nabholz, Ms. Lee and Mr. Demosky are officers of Suncor Energy Services Inc., which provides major projects management, human resources and communication, business services and other shared services to the Suncor group of companies.

(2) This information reflects the positions of officers at December 31, 2008.

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