2006 Annual Report

SUNCOR ENERGY

FIRST IN oil sands
STILL taking the lead

You don't stand out from the competition by moving with the current.

In 1967, we pioneered commercial development of the oil sands. Since then, Suncor Energy Inc. has distinguished itself as a major North American energy producer, with a strategy focused on the oil sands of northern Alberta – one of the world's largest petroleum resource basins. Strong integration of upstream production and downstream market connections, a broad customer base and a focus on technology, innovation and sustainability are all hallmarks of the Suncor story.

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 60 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 58 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.

CHARTING a bold course
CHARTING strong results

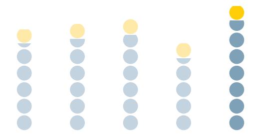
Suncor's strong financial returns are evidence of our ability to generate shareholder value by delivering on strategic growth opportunities.

Key indicators

Year ended December 31 ($ millions)	2006	2005	2004	2003	2002
Financial					
Revenues	**15 829**	11 129	8 705	6 611	5 071
Capital and exploration expenditures	**3 613**	3 153	1 847	1 322	878
Total assets	**18 781**	15 149	11 774	10 489	8 978
Dollars per common share					
Net earnings attributable to common shareholders – basic	**6.47**	2.54	2.38	2.45	1.66
Net earnings attributable to common shareholders – diluted	**6.32**	2.47	2.33	2.29	1.64
Cash flow from operations (1)	**9.87**	5.43	4.44	4.53	3.11
Cash dividends	**0.30**	0.24	0.23	0.1925	0.17
Market price of common stock at December 31 (closing)					
Toronto Stock Exchange (Cdn$)	**91.79**	73.32	42.40	32.50	24.70
New York Stock Exchange (US$)	**78.91**	63.13	35.40	25.06	15.67
Key ratios					
Debt to debt plus shareholders' equity (%)	**21.1**	33.8	31.6	43.5	53.2
Net debt to cash flow from operations (1) (times)	**0.4**	1.2	1.1	1.3	2.3
Return on shareholders' equity (%)	**39.7**	21.3	24.6	32.9	29.8

Production

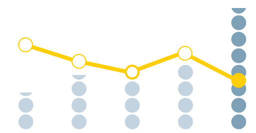
(thousands of barrels of oil equivalent per day)



	02	03	04	05	06
Natural Gas	33.7	34.9	36.8	34.8	**34.8**
Oil Sands	205.8	216.6	226.5	171.3	**260.0**
Total	239.5	251.5	263.3	206.1	**294.8**

Cash Flow from Operations (1)/Net Debt

($ millions)



	02	03	04	05	06
Cash flow from operations	1 393	2 040	2 013	2 476	**4 533**
Net debt	3 204	2 577	2 159	2 891	**1 871**

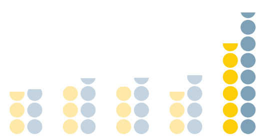
Net Earnings

($ millions)

02	03	04	05	06
743	1 100	1 076	1 158	**2 971**

Return on Capital Employed (1)

(per cent)



	02	03	04	05	06
ROCE (2)	14.2	16.3	16.0	14.3	**30.4**
ROCE (3)	15.1	18.7	18.9	19.7	**40.6**

(1) Non-GAAP measure.

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

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

Resources

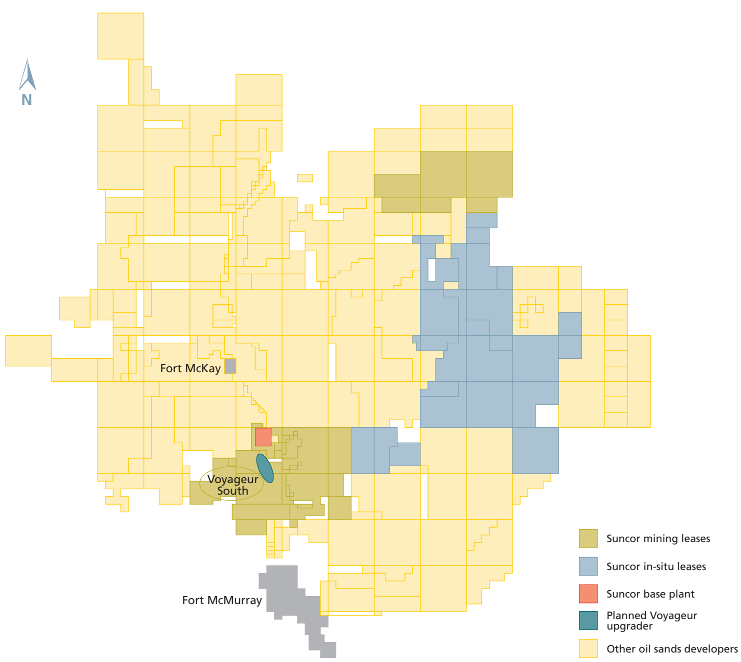
THE ADVANTAGE of being first

Suncor's business is built on the foundation of one of the world's largest resource basins – the Athabasca oil sands. Since pioneering oil sands development in 1967, Suncor has secured some of the largest leaseholdings in the Athabasca region and is the first and currently only company to use both mining and in-situ resource development technologies.

Our leases hold estimated remaining recoverable resources* with the potential to produce 15 billion barrels of conventional quality oil. But unlike conventional oil development, very little exploration is required to establish the location, size and quality of our reserves.

Mining

Surface mining leases adjacent to Suncor's production facilities provide the majority of our current bitumen production. Suncor was the first oil sands company to shift operations to the more flexible and cost-effective truck and shovel mining. Now, we're taking a leading role in deploying new mobile mining technology that is expected to improve operational performance and reduce air emissions.



These technological advances are expected to play a role in Voyageur South, a mine expansion we are planning immediately southwest of our current operations. Pending regulatory approval, this oil sands mine is expected to provide another reliable source of bitumen for our planned expansion of upgrading capacity – and help launch the next stage of our integrated growth strategy.

In-situ

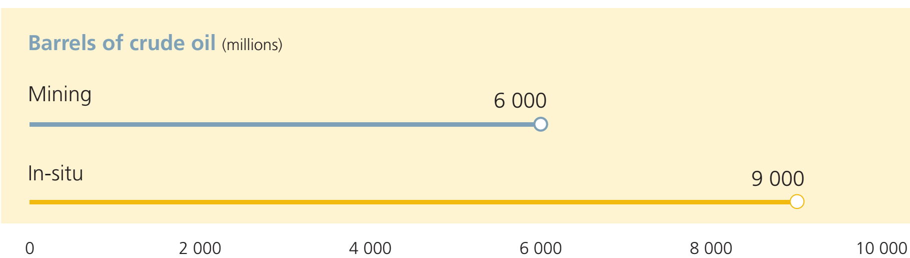
Suncor has built on our first-in status as an oil sands miner to also become a leader in in-situ development – and our Firebag steam-assisted gravity drainage (SAGD) project is a key part of our long-term growth strategy.

With two stages of Firebag in operation, Suncor is investigating new ways to reduce costs and environmental impacts. One example is the use of mechanical pumps to improve operational performance and reduce natural gas consumption – the biggest cost factor and largest emissions source in our SAGD operations.

Third party agreements

To provide greater flexibility to our bitumen feedstock, we supplement our own mining and in-situ operations through third party supply and processing agreements. An important component of this strategy is anticipated in 2008 with an agreement to process up to 27,000 barrels per day (bpd) of third party bitumen. Suncor continues to look for innovative supply agreements as planned bitumen production in the Athabasca region is expected to expand more quickly than upgrading capacity.

15 billion barrels of resources*



* The term "resources" refers to a best estimate of remaining recoverable resources, which is the sum of proved plus probable reserves and best estimate "contingent resources", presented on a gross basis as barrels of synthetic crude oil converted from barrels of bitumen. "Contingent resources" are Suncor's independent reserve evaluators' best estimate of resources they consider to be potentially recoverable from known accumulations under reasonable economic and operating conditions for areas of our oil sands deposits not classified as reserves. These areas are not classified as reserves due to the absence of a firm plan to develop within a reasonable time frame and due to higher uncertainty as a result of lower core-hole drilling density. As U.S. companies are prohibited from disclosing estimates of probable reserves for non-mining properties and resources for oil and gas or mining properties, Suncor's resource estimates will not be comparable to those made by U.S. companies. For a description of constant cost and pricing assumptions used to evaluate the proved and probable reserves included in our resource estimate, and a description of our reserves under U.S. reporting requirements, see pages 35 to 38.

Bitumen delivery targets

2008

15% to 20% in-situ, Firebag Stages 1 and 2

75% to 80% mined from Millennium

5% from third parties

2012

30% in-situ, Firebag Stages 1 to 6

65% mined from Millennium, North Steepbank and Voyageur South

5% from third parties

Production

BUILDING for the next leap in production

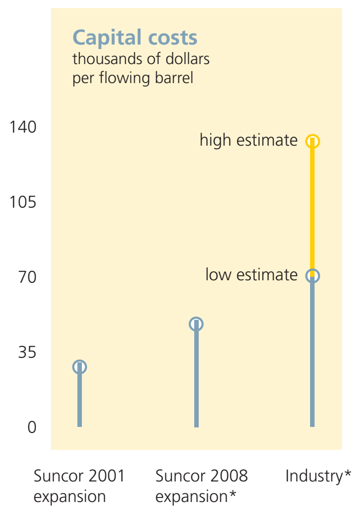
With abundant bitumen supplies to draw on, Suncor doesn't need to look for new resources. Instead, we look for new ways to expand and improve the extraction and upgrading of bitumen to higher value synthetic crude oil. Our goal: production of more than half a million barrels per day in 2010 to 2012.

It's a big number, but the more important figure in the capital-intensive oil sands business is the return we provide to shareholders. As Suncor prepares to leap ahead in production capacity, we remain focused on the goal of achieving a return on capital employed of at least 15% at mid-cycle oil prices. Suncor's own engineering, procurement and construction team – the most experienced in the oil sands industry – will lead the planning and execution of our growth plans every step of the way.

Current plans

The next major milestone in Suncor's growth plans is an increase in oil sands production capacity to 350,000 bpd in 2008. The centrepiece of this expansion is the addition of a third coker set to Upgrader 2. When complete, this expansion is expected to increase production capacity by 35% – a magnitude of change that few producers of our size can match.

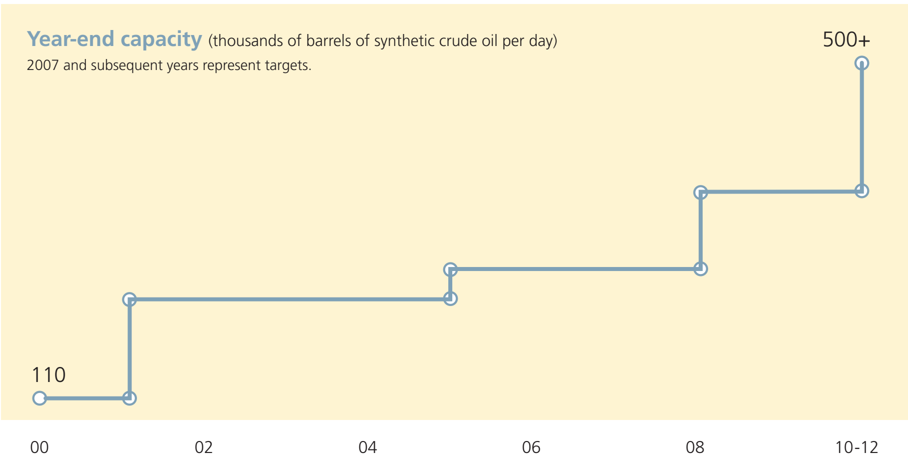
Beyond 2008, the pieces of our plan to expand daily production even further to more than half a million barrels are coming together. In November 2006, Suncor received regulatory approval to build a third oil sands upgrader. The planned facility is expected to have cokers that will be among the largest in the world. Planned hydrotreating facilities will allow Suncor to fully upgrade the majority of our production slate to sweet synthetic crude oil.



* Projections from company disclosures.

While our primary focus is on delivering current expansion plans, Suncor is laying the groundwork for growth beyond 2012. The blueprints for those plans haven't yet been drawn, but carbon capture and storage and harnessing energy from petroleum coke gasification could play a role in shaping the economic and environmental performance of future upgrading assets.

Increasing oil sands production



Natural gas

While oil sands operations are the centerpiece of our strategy and growth plans, Suncor's natural gas business is also key to creating value in our uniquely integrated operations. Producing our own natural gas provides a price hedge against purchases for internal consumption at our oil sands and refining operations. In 2006, we produced 191 million cubic feet per day of natural gas, enough to power Suncor's operations while still selling a surplus into the North American gas market. Our focus is on leveraging our expertise in deep Foothills prospects in western Alberta and northeastern British Columbia with a goal of increasing natural gas production by 3% to 5% annually.

Daily production goals

2008

185,000 barrels of sour from Upgraders 1 and 2

165,000 barrels of sweet from Upgraders 1 and 2 (and via hydrotreating)

2012

190,000 barrels of sour from Upgraders 1 and 2

360,000 barrels of sweet from Upgraders 1, 2 and proposed Voyageur upgrader

THE FIRST integrated oil sands company

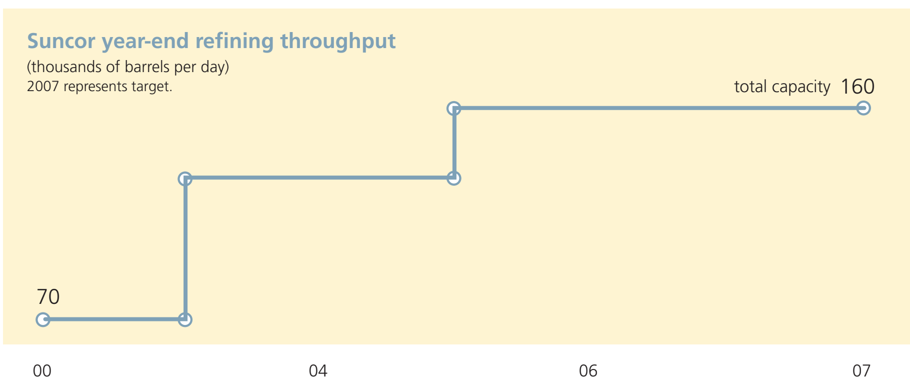
As oil sands-based crude products become a growing part of the North American energy market, industry watchers have begun to question how synthetic crude production will connect to refinery capacity.

Suncor was the first company to provide a definitive answer to that question with a strategy that integrates oil sands production with a strong presence in the downstream. Suncor's refining and marketing strategy is aimed directly at building on the competitive advantage of having our oil sands production securely connected to customers in Canada and the United States, the largest crude oil market in the world.

Energy marketing

With a portfolio of crude oil products, including heavy and sour blends, our goal is to match our products to the demands and capabilities of refiners, creating value for Suncor and our customers. Suncor is the leading marketer of oil sands products and every day we sell hundreds of thousands of barrels of crude through a portfolio of both directly owned and contracted pipeline capacity, allowing flexibility to respond to our customers' diverse needs and changing market conditions.

Integrating production



Downstream refining

In 1984, Suncor established itself as the first truly integrated oil sands company with modifications to our Sarnia refinery that enabled the processing of a high volume of sweet oil sands crude. We are now taking that integration strategy further with upgrades to both our Sarnia and Commerce City refineries that will allow both facilities to process oil sands sour crudes.

At our 90,000 bpd capacity Commerce City refinery in the metropolitan Denver area, modifications completed in 2006 allow us to process higher volumes of oil sands synthetic crude blends, including up to 15,000 bpd of oil sands sour blends. When completed in 2007, improvements to our 70,000 bpd capacity Sarnia refinery are expected to allow the facility to process up to 40,000 bpd of sour crude blends, finishing the work of upgrading oil sands products at a lower capital cost than modifying or expanding existing facilities in northern Alberta.

Retail

Suncor extends our product reach into the retail market through joint venture service station operations and long-term supply contracts in addition to Phillips 66® stations in Colorado* and Suncor-owned Sunoco stations in Ontario. These retail networks provide an opportunity to capture further value from our refined products. Retail outlets in both regions are undergoing renovations and improvements to help maintain and build Suncor's market share in this highly competitive sector.

Renewable energy

While working to responsibly develop hydrocarbon resources, Suncor remains an industry leader in developing renewable energy sources. Suncor has sold lower-emission ethanol-blended gasoline for more than a decade and, in 2006, we completed construction of Canada's largest ethanol plant. We are investigating possible expansion of this facility as we continue to look for new opportunities in the biofuels market.

Suncor is also targeting growth in renewable wind energy. By late 2007, the company plans to have a total of four wind power projects in operation with a combined capacity of 147 megawatts of renewable energy as an alternative to hydrocarbon-fuelled generation.

Together, these renewable energy investments are expected to offset the equivalent of nearly 600,000 tonnes of carbon dioxide (CO_2) annually by the end of 2007.

* Suncor in Canada is separate and unrelated to Sunoco in the United States, which is owned by Sunoco, Inc. of Philadelphia. Suncor Energy (U.S.A.) Inc. is an authorized licensee of the Phillips 66® brand and marks in the state of Colorado.

Market plans

2008

55,000 bpd sour crude to Suncor refineries

130,000 bpd sour crude to short and long-term contracts with various customers

165,000 bpd sweet crude to Edmonton, U.S. Pacific NW, U.S. Rockies and Chicago area

2012

55,000 bpd sour crude to Suncor refineries

135,000 bpd sour crude to other customers

360,000 bpd sweet crude to Edmonton, U.S. Pacific NW, U.S. Rockies, Chicago and Cushing, Oklahoma, with options to the West Coast and Asia

INTEGRATION advantage

Suncor has four major business divisions in Canada and the United States and more than 5,500 employees. Our core oil sands business is supported by natural gas production in Western Canada and downstream refining, marketing and retail businesses in Ontario and Colorado.

Oil Sands

The foundation of Suncor's business and future growth strategy is the Athabasca oil sands, located near Fort McMurray, Alberta. The oil sands business recovers bitumen through conventional surface mining and steam injection technologies and upgrades it into refinery-ready crude oil products and diesel fuel. Future investment continues to centre on increasing production, controlling operating costs and improving our environment, health and safety performance.

Natural Gas and Renewable Energy

Based in Calgary with operations in western Alberta and northeastern British Columbia, this business manages development and production of natural gas to provide a "price hedge" against purchases for internal consumption at our oil sands and refining operations. Suncor's natural gas production is targeted to increase by 3% to 5% per year to offset growing internal demand. The business also supports Suncor's sustainability goals by managing investment in wind energy projects and developing strategies to reduce greenhouse gas emissions.

Energy Marketing and Refining – Canada

Suncor's Canadian downstream operations market the company's natural gas production and a range of refinery-ready petroleum products to commercial and industrial customers. In addition, products from our Sarnia, Ontario refinery are sold to commercial customers in Canada and the northeastern United States, and to retail customers in Ontario through more than 500 Suncor-owned, Sunoco-branded and joint venture-operated service stations.

Refining and Marketing – U.S.A.

Suncor's Commerce City refining operations, near Denver, and Phillips 66®-branded retail stations connect us to industrial, commercial and retail markets in the U.S. Rocky Mountain region. While we build on our position as a major supplier of energy products and the largest refiner in the region, our Colorado team is also leading Suncor's efforts to expand further in the U.S. refining market through potential acquisitions or joint ventures.

GROWING strategically

Suncor's large resource base, growing production capacity and access to the North American energy market are the foundation of an integrated strategy aimed at driving profitable growth, a solid return on capital investment and strong returns for our shareholders.

Growing responsibly

Suncor is a company that believes in leading by example – and when it comes to sustainable development, we are doing just that.

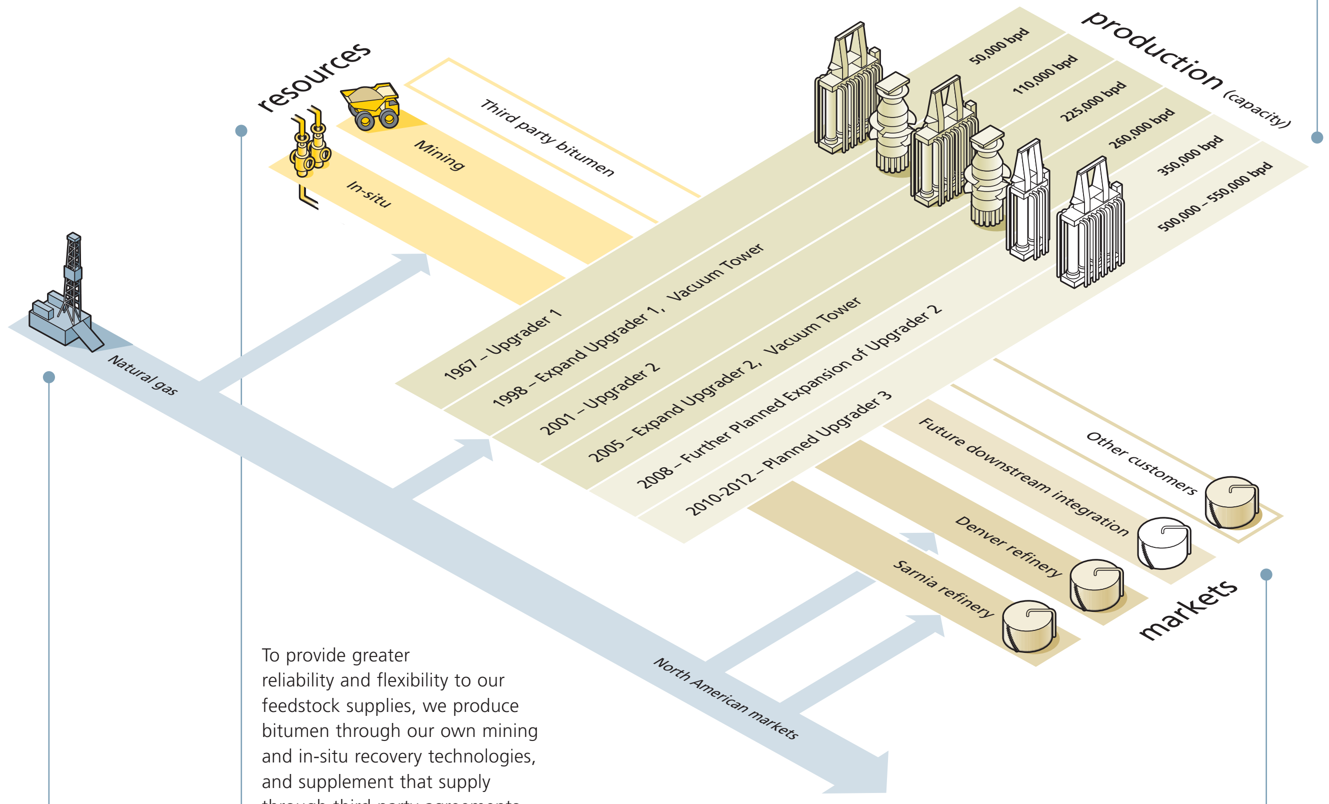
As early as 1992, Suncor adopted a vision of sustainable development that has guided our business strategy ever since. We call it our "triple bottom line." Our vision is that energy – in all its forms – should be developed in a way that provides economic prosperity, promotes social well-being and helps preserve a healthy environment.

As part of that vision, Suncor took an early, proactive stance on the climate change challenge and we continue to invest in new technologies to improve our energy efficiency and to better manage emissions of CO_2 and air contaminants.

Suncor is also taking a leading role in developing renewable energy sources. We are Canada's largest producer and marketer of ethanol-blended gasoline and by the end of 2007, we expect to have our fourth wind power project in operation.

As we move ahead, Suncor is developing company-wide strategies to reinforce a conservation ethic in all our operations and among all employees. On the critical issue of water use, we are making progress through recycling and reusing. As a result, we are planning no net increase in water consumption when our third oil sands upgrader begins operations.

A staged approach to increasing our crude oil production capacity allows Suncor to better manage capital costs and incorporate new ideas and new technologies into our facilities.



To provide greater reliability and flexibility to our feedstock supplies, we produce bitumen through our own mining and in-situ recovery technologies, and supplement that supply through third party agreements.

Suncor takes an active role in connecting supply to consumer demand with a diverse portfolio of products, downstream assets and markets.

We produce conventional natural gas as a price hedge against the cost of energy consumption.

Our investments in renewable wind energy and biofuels are a key part of Suncor's climate change action plan.

LEAPING ahead

"The Suncor way is about focusing on long-term goals, rather than swimming off in whichever direction the current of the day might take us."

Rick George
president and chief executive officer

Being first is a privilege – and a challenge. In 1967, when Suncor Energy became the first company to commercially produce synthetic crude oil from the oil sands, many analysts believed the fledgling industry would never be economically feasible.

Three decades later, skeptics were again in evidence as we launched a major oil sands growth strategy at a time when world oil prices languished at less than $15 per barrel. In each instance, Suncor persisted – and prevailed. As a company, we've learned it's important to swim our own course, even if it sometimes means entering uncharted waters.

Just as importantly, Suncor understands the wisdom of looking long and hard before leaping ahead. As we mark our 40th anniversary in the oil sands business – and grow nearer to our strategic goal of producing more than half a million barrels per day – we continue to follow our own template for success. The Suncor way is about achieving steady and reliable growth through a combination of innovation, prudent management and integrated planning. Above all, it means focusing on long-term goals, rather than swimming off in whichever direction the current of the day might take us.

An industry leader

With leases containing an estimated 15 billion barrels of remaining recoverable resources, Suncor is clearly in the oil sands business for the long haul. But while the resource base is massive, our approach to developing it has always been measured. Suncor's record is one of careful planning and delivering on what we promise. We believe in earning investors' confidence, one day and one step at a time.

Suncor pioneered what is becoming an industry model for integrated planning. Our growth strategy is built on three pillars. First, there's the resource base itself – some 200,000 hectares of leases we have quietly assembled over the past four decades.

Second is Suncor's approach to increasing crude production, which follows a manufacturing model. Spared the time, risk and expense of conventional oil exploration in increasingly remote corners of the globe, we can concentrate our investments on harnessing technology to develop our proven assets in the most cost-effective and energy-efficient manner.

The third strategic pillar is access to markets. As production levels expand, we plan to steadily increase our market connections to build a reliable customer base in Canada and the United States, which together form the world's largest energy market. At the same time, we have strengthened our

Together with a keen focus on our environmental and social responsibilities, Suncor's innovative growth strategy has a proven track record of delivering shareholder value.

"internal markets" by fully integrating our diverse holdings and operational capabilities – including refineries, retail gas outlets and natural gas production facilities. This, in turn, gives us a built-in advantage to help weather the inevitable commodity price fluctuations of the energy business.

As we've grown, Suncor has led by example. We were the first Canadian oil sands company to purchase U.S. refinery assets – an important link to a crucial market. We were also the first to make the business case for investing significantly in renewable energy. And Suncor remains the only oil sands company with both mining and in-situ operations.

Together with a keen focus on our environmental and social responsibilities, Suncor's innovative growth strategy has a proven track record of delivering shareholder value – an average annual return of more than 30% since we became a publicly traded company in 1992. We did this over a period when commodity prices went up – and went down. The key throughout was to focus on those areas we could control, including ensuring safe, reliable operations, managing input costs and maintaining a strong balance sheet.

Forty years after we first began to mine the oil sands, Suncor remains an industry pioneer. Just as the technology of the late 20th century helped unlock this vital resource, the technology of the early 21st century is now bringing it to an eager marketplace. We are proud to play our part in this exciting development. And, as always, we will do so the Suncor way.

2006 highlights

Suncor began 2006 by passing another significant milestone – the sale of our billionth barrel of oil sands crude since operations began in 1967. Though satisfying to achieve, it's important to note that our next billion barrels should be reached much quicker than the first. That's because of the progress we've made in delivering a multi-phased growth plan launched nearly a decade ago.

The first phase, known as Project Millennium and completed in 2001, more than doubled Suncor's production capacity to 225,000 barrels per day (bpd). That same year, we launched the Voyageur growth strategy, which took production capacity to 260,000 bpd in 2005 and continues to see us on track to increasing production to 350,000 bpd in 2008, and then again to between 500,000 and 550,000 bpd in 2010 to 2012. Those numbers represent an average targeted production growth rate of 15% per year over the next six years, a rate few major energy companies can match.

This brings us to another obvious highlight of 2006 – the regulatory approval granted in November for Voyageur's final phase, covering the construction of a third upgrader. The successful completion of the most complex regulatory filing in Suncor's history was testament to the thousands of hours of consultation between Suncor and local, regional and provincial stakeholders.

The year also included several significant developments in Suncor's downstream operations. We successfully completed a US$445 million upgrade to our Commerce City refinery, near Denver. In addition to modifications to meet clean fuels regulations, the upgrades improve the facility's environmental performance and enable Suncor to integrate a broader range of crude oil products – in particular, sour crude oil from our oil sands operations.

Suncor also completed the first part of a planned two-phase $960 million investment in our refinery in Sarnia, Ontario, with the construction of a new diesel desulphurization unit. This work is being followed, in 2007, by refinery tie ins that will allow the Sarnia facility to process up to 40,000 bpd of oil sands sour crude blends.

In nearby St. Clair Township, Suncor marked the opening of Canada's largest ethanol production facility. The $112 million facility is expected to produce 200 million litres of ethanol annually, which will be blended with the gasoline sold at Suncor-owned Sunoco retail stations across Ontario.

At the same time, our natural gas operations continued to focus on high-impact, deep gas prospects in pursuit of Suncor's long-term goal of expanding gas production by 3% to 5% per year. Though volumes have been relatively flat over the past two years, this part of our business continues to provide Suncor with a "price hedge" that earns steady returns and more than compensates for the cost of natural gas used in our operations.

Taken together, Suncor's integrated operations reflect our focused approach to building shareholder value. While oil sands production is, and will remain, a primary focus, Suncor's various business divisions form a single system. It doesn't make sense for petroleum producers to invest in products without a market, just as it doesn't serve refiners to invest in markets for which there is an insufficient supply of feedstock. To truly succeed, the upstream and downstream must work together.

Plans and priorities

So where do we go from here? Because our company is in this very much for the long haul, it's probably best to answer that question based on our short-term and intermediate goals as well as our long-term vision for developing Suncor's oil sands assets.

2007-2012: building on a strong foundation

For 2007, Suncor's Board of Directors approved an unprecedented $5.3 billion in capital spending, up 50% from the previous record year of 2006. Of the budgeted spending, approximately $4.4 billion is dedicated to Suncor's oil sands operations. This year's capital spending plan reflects the wealth of growth options and opportunities our company enjoys over the next several years. As we pursue those opportunities, managing our capital spending to provide a solid return on investment must remain a priority.

Work is already underway on the expansion of Suncor's Firebag in-situ operations, with construction expected to be completed in 2007. As well, management expects to seek final Board of Directors approval for Stage 3 of our in-situ operation later this year. Detailed engineering and site preparation work for both the Voyageur upgrader and the Steepbank mine extension is also in progress.

Steady and reliable production growth will help us manage cash operating costs, which are targeted at $21.50 to $22.50 per barrel in 2007. As Suncor invests in future growth, maintaining a strong balance sheet is critical. Our efforts to reduce debt over the past five years, combined with the benefits of increasing production, provide a strong financial foundation as we continue to grow.

Over the past several years, Suncor has focused on safe project delivery that is "on time and on budget". It's a commitment we hope to maintain as we continue to benefit from the most experienced engineering, procurement and construction team in the oil sands industry. However the realities of our hot economy and very active energy sector will put pressure on capital projects.

Beyond 2012: the next leap

Because so much of the past decade has been about planning and implementing Suncor's path towards the half million barrel per day production target, it's sometimes been easy to think of this as an end point rather than what it really is – a new beginning.

As a result, it's time to start talking frankly about "growth beyond Voyageur." Suncor's plans for an expanded mine, to be located southwest of our existing operation, are one signal of where we are headed. We expect the regulatory process to take up to two years. Pending approval, Suncor hopes to begin construction in 2009, with operations coming online in 2011.

Expanded mine development would serve a dual purpose. In its early production phase, the bitumen from this project is expected to provide additional feedstock flexibility for our planned half million barrel per day upgrading capacity. Over the longer term, it is expected to provide a reliable source of bitumen for future growth.

It's important to note that this mine will likely form just one part of the next planned leap in our integrated growth strategy. However, in whatever we do, one of the keys to future success will continue to be a flexible approach to emerging technologies. Suncor continues to invest in research aimed at reducing the costs and environmental footprint of its mining, in-situ and refining operations. And these technologies will develop at different times – for example, our plan to introduce mobile mining technology, which would eliminate most of the haul fleet for transporting ore, is a timely advance for new mine developments.

Continuing challenges

Well-managed operations, excellent project management, a strong balance sheet and investment in new technology – all are critical to our growth plans. But sometimes the oil sands industry is impacted by forces largely beyond our control.

Two recurring challenges in recent years are a continent-wide shortage of skilled workers and hyper-inflated costs due to materials and services being in tight supply and high demand. Both challenges persist, but there does appear to be some light at the end of the tunnel – especially on the materials side.

A slowdown in the economy in the United States and Central Canada is reducing the demand for concrete and tempering the prices for steel – though in no way rolling back the 50% cost increase we saw over the past four years. The winding down of the reconstruction effort that followed the August 2005 Katrina hurricane also means less competition for scarce materials.

As for workforce shortages, this remains a pressing industry-wide concern – one that, if left unaddressed, could delay or derail important projects and the economic benefits they generate.

For our part, Suncor continues to support innovative apprenticeship and skills training initiatives at technical institutes and colleges (see sidebar). We're also working to resolve regional labour bottlenecks in Fort McMurray. For example, we plan to have up to a third of the fabrication for our next oil sands upgrader and supporting infrastructure completed off site and we're looking to source more materials and products from across Canada and beyond our borders. We expect this will not only reduce the risk of labour-related delays – it will help spread the economic benefits of our business more widely.

Responsible development

At Suncor, we've always believed the path forward must be based on a vision of sustainable development. Simply put, this means developing energy in a way that provides economic prosperity, promotes social well-being and preserves a healthy environment. This view, and in particular concern for the environment, is now high on the public agenda – right where it's been at Suncor since the early 1990s. We've pursued this path because we believe that targeting strong results in economic, social and environmental performance provides a solid foundation for growth by helping us earn continued support for our current operations and future plans.

Suncor remains an industry leader in pursuing environmentally responsible energy development. We were the first oil sands company to voluntarily adopt an internal Climate Change Action Plan and report annually to stakeholders on our progress in managing greenhouse gas emissions and improving our energy efficiency.

We've also taken a leading role in developing renewable energy sources. In late 2007, Suncor expects to commission our fourth wind power project. Our investments in renewable wind energy, together with our new St. Clair ethanol plant, are expected to offset the equivalent of nearly 600,000 tonnes of carbon dioxide annually. We are considering an expansion of our ethanol plant and are targeting development of a new wind power initiative every 12 to 18 months. At the same time, we are realizing reductions in the intensity of air emissions and water use at all of our operations. Significantly, our third oil sands upgrader anticipates no net increase in water use despite a doubling in production capacity.

Addressing the labour gap

Recruit, retain and develop Attract and employ the right workforce with the right skills by offering career development and fair rewards in a challenging environment.

Support community development Help build strong, vibrant communities that will attract workers to the oil sands region. This includes working to address infrastructure concerns, relocation challenges and improving camp accommodations.

Partner with industry Work cooperatively with industry to avoid unnecessary workforce scheduling conflicts and to make the best use of available workers.

Encourage innovative labour practices Support far-sighted labour policies and practices that assist Canada's economic growth.

Invest in technology Harness technology to make the best possible use of our workforce. For example, new mining technology requires fewer workers, allowing us to redeploy to areas where skills are in demand.

I encourage shareholders to learn more about our "triple bottom line performance" by reading our biennial Report on Sustainability. It is a key part of a governance philosophy that puts a premium on transparent disclosure, high standards of conduct and strong, effective corporate management. Suncor's Board of Directors, who oversee all aspects of governance, are outstanding stewards of shareholders' long-term interests. They also excel at challenging management to exceed expectations – and I would like to recognize them for their guidance and support.

Finally, there's the heart and soul of our company, Suncor's 5,500 employees – the people who put our plans into action and who have led the charge on delivering growth, innovation, reliability and – most importantly – workplace safety, which is at the core of operational excellence. In a highly competitive industry we strive to be an employer of choice. I am honoured that Suncor is that choice for so many bright newcomers to our industry. And equally, I am grateful to the veterans who have stuck with Suncor through many challenges and driven so much of the innovation and leadership that defines Suncor. You've built a company we can all be proud of.

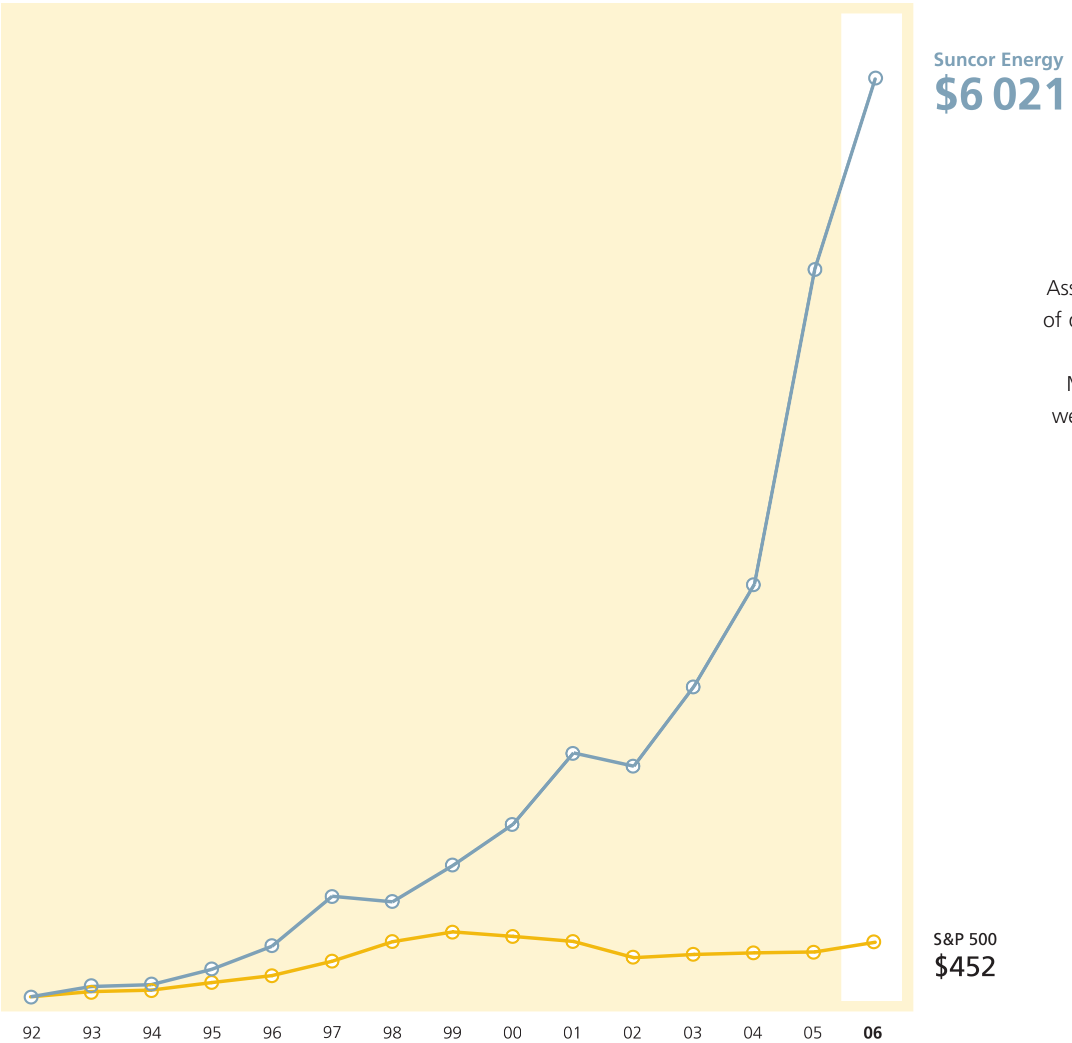
As we look ahead to Suncor's next 40 years as an oil sands pioneer, we know we have the expertise and the enthusiasm to keep swimming our own course – to be both bold and strategic. I feel privileged to be part of this team and, on behalf of Suncor's employees, management and your Board of Directors, I thank you for your continued support.

Rick George

Rick George
president and chief executive officer

DELIVERING value

Over the past 15 years, Suncor's total return on investment has outperformed the S&P 500 by more than 1,200%.



Equity appreciation
Assuming the reinvestment of dividends, an investment of $100 in Suncor on March 18, 1992, the day we became publicly traded, would have grown to more than $6,000 by the end of 2006.

Leadership team

LEADING the way

Suncor's senior management team is structured to reflect the company's primary challenge in the years ahead – delivering significant growth while maintaining operational excellence in every aspect of our operations.

Under the leadership of President and CEO Rick George, Suncor's senior management team is tasked with ensuring the company continues to be an industry leader on both fronts.

Steve Williams, chief operating officer (COO), reports to the CEO as a member of Rick's growth-oriented executive team. He is responsible for achieving safe, reliable and cost effective operations in a manner that is responsible to our environment and our communities. Steve's operating team consists of:

- **Kirk Bailey, executive vice president, Oil Sands** is responsible for keeping efficiency and reliability at the forefront of our oil sands operations, meeting production targets and driving industry-leading safety and productivity.
- **Dave Byler, executive vice president, Natural Gas and Renewable Energy** is charged with meeting our strategic goals by increasing natural gas production to help offset growing internal demand, while also developing our renewable energy business.
- **Tom Ryley, executive vice president, Refining and Marketing** is focused on increasing alignment and integration within Suncor's downstream businesses in Ontario and Colorado, as well as marketing Suncor's refined products.

In addition to the COO, Rick George's executive team includes:

Mike Ashar, executive vice president, Strategic Growth and Energy Trading, is focused on initiatives to support future growth, with emphasis on Suncor's strategies to expand production beyond 2012. He is also responsible for energy marketing and logistics.

Ken Alley, senior vice president and chief financial officer, is charged with maintaining a strong balance sheet and solid financial base, earning the support of shareholders as Suncor pursues annual capital spending of approximately $5 billion.

Terry Hopwood, senior vice president and general counsel, is Suncor's chief legal officer, supporting our growing operations in business-to-business negotiations and helping us navigate an increasingly complex regulatory environment.

Sue Lee, senior vice president, Human Resources and Communications, is responsible for strategies to recruit and retain the people who put our business plans into action, while also engaging community and government stakeholders to ensure we maintain broad support for our growth plans.

Kevin Nabholz, executive vice president, Major Projects, is charged with safely bringing in growth projects on time and on budget, across all of Suncor's operations.

Jay Thornton, senior vice president, Business Integration, focuses on delivering cost-efficient services, effective cross-company integration of processes and technology and efficient supply-chain management.

2006 what we promised and what we delivered

Increase annual oil sands production to 260,000 bpd at cash operating costs of $18.75 to $19.50 per barrel. Upgraded oil sands production came in slightly below target at 253,800 bpd. At $21.70 per barrel, we also missed cash operating costs per barrel targets, primarily due to increased maintenance and contract labour costs.

Advance plans for increased bitumen supply. Average daily production from Firebag Stages 1 and 2 increased by 76%. Firebag Stage 3 received regulatory approval, as did the Steepbank mine extension, which will replace depleted mining production from current operations.

Advance plans for increased upgrader capacity. Plans to increase production capacity to 350,000 bpd in 2008 remain on schedule and on budget with construction about 70% complete at year-end. Plans to increase upgrading capacity to more than 500,000 bpd received regulatory approval.

Increase natural gas production to an average 205 to 210 mmcf per day. At 191 mmcf per day, natural gas production fell short of targets due to pipeline and processing facility constraints and lower than expected drilling results.

Reduce lost-time injury frequency. Employee and contractor lost-time injury frequency, a key metric of operational performance, was reduced by 35% in 2006.

Focus on enterprise-wide efficiency. Suncor completed a company-wide centralization of support services and an associated upgrade to many business processes and systems.

Advance downstream integration. Modifications to meet low-sulphur fuel regulations were completed at both Suncor refineries. Modifications to the Denver-area refinery also allowed the facility to process up to 15,000 bpd of oil sands sour crude.

Maintain a strong balance sheet. Suncor's net debt was reduced to $1.9 billion – about 40% of 2006 cash flow from operations.

Continue to pursue energy efficiencies, greenhouse gas offsets and new, renewable energy projects. In 2006, Suncor commissioned Canada's largest ethanol plant and our third wind power project. The two projects offset the equivalent of 400,000 tonnes of carbon dioxide per year.

2007 our targets and how we'll reach them

Achieve annual oil sands production of 260,000 to 270,000 bpd with a cash operating cost average of $21.50 to $22.50 per barrel. Steady and reliable production will help us manage cash operating costs.

Increase natural gas production to an average 215 to 220 mmcf equivalent per day. We expect to bring several existing wells into production and will continue to focus on high-volume, deep gas prospects in 2007.

Advance plans for increased bitumen supply. Launch the regulatory, consultation and engineering work required to extend mining operations; receive Board of Directors support for Stage 3 in-situ development, including cost estimates.

Safely complete all expansion tie ins. Complete a 50-day shutdown on Upgrader 2 to tie in expanded facilities that are expected to increase production to 350,000 bpd in 2008. At the Sarnia refinery, complete a 65-day shutdown to tie in new and modified equipment to allow the processing of up to 40,000 bpd of oil sands sour crude.

Advance plans for increased upgrader capacity. Complete the detailed engineering necessary to seek Board of Directors approval to proceed with construction of our planned third oil sands upgrader, a key component of achieving more than half a million bpd by 2010 to 2012.

Continue to focus on safety. Expand safety performance measures to include first aid incidents, as well as lost-time incidents.

Focus on enterprise-wide efficiency. Improved operational reliability is the goal of establishing a single-vendor, performance-based maintenance contract for all Canadian facilities.

Maintain a strong balance sheet. With capital spending plans of more than $5 billion, a strong balance sheet will be critical. Suncor is targeting debt at a maximum of two times cash flow.

Continue to pursue energy efficiencies, greenhouse gas offsets and new, renewable energy projects. We plan to continue investment in biofuels and to commission our fourth – and largest yet – wind power project in 2007. Complete the stakeholder consultation and preliminary engineering needed to determine feasibility of expanding the St. Clair ethanol facility.

Management's discussion and analysis

February 28, 2007

This Management's Discussion and Analysis (MD&A) contains forward-looking statements. These statements are based on certain estimates and assumptions and involve risks and uncertainties. Actual results may differ materially. See page 60 for additional information.

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 58.

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.

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

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

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

In order to provide shareholders with full disclosure relating to potential future capital expenditures, we have provided cost estimates for projects that, in 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 and the range of cost estimates associated with an "on-budget" project, see the "Significant Capital Project Update" on page 27.

Suncor overview and strategic priorities

Suncor Energy Inc. is an integrated energy company headquartered in Calgary, Alberta. We operate four 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** (NG) produces natural gas in Western Canada, providing revenues and serving as a price hedge against the company's internal natural gas consumption in our oil sands and downstream operations. This business also supports Suncor's sustainability goals by managing investment in wind energy projects and developing strategies to reduce greenhouse gas emissions.
- **Energy Marketing and Refining – Canada** (EM&R) operates a 70,000 barrel per day (bpd) capacity refinery and a 200 million litre per year ethanol plant, both in Sarnia, Ontario. As well, EM&R markets refined petroleum products to customers primarily in Ontario and Quebec. EM&R also manages our company-wide energy marketing and trading activities and sales of all Oil Sands and NG production. Financial results relating to the sales of Oil Sands and NG production are reported in the respective business segments.
- **Refining and Marketing – U.S.A.** (R&M) operates a 90,000 bpd capacity refinery in Commerce City, Colorado, as well as related pipeline assets. R&M markets refined petroleum products to customers throughout Colorado.

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

Suncor's strategic priorities are:

Operational:

- 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 that meet market demand.
- Increasing production capacity and improving reliability through staged expansion, continued focus on operational excellence and worksite safety.
- Integrating Oil Sands production into the North American energy market through Suncor's refineries and the refineries of other customers to reduce vulnerability to supply and demand imbalances.
- Managing environmental and social performance to reduce intensity of our water use, air and greenhouse gas emission and our impact on the 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 through a strong focus on operational excellence, economies of scale and continued management of engineering, procurement and construction of major projects.
- Reducing risk associated with natural gas price volatility by producing natural gas volumes that offset purchases for internal consumption.
- Maintaining a strong balance sheet by closely managing debt and capital spending.

We expect our current growth to 350,000 bpd in 2008 to support an annual average 15% return on capital employed (ROCE) assuming a US$35 West Texas Intermediate (WTI) crude oil price and a Cdn$/US$ exchange rate of $0.80. Longer term, we are targeting a 15% ROCE at a sustainable long-term crude oil price. Estimates of ROCE are highly sensitive to, among other factors, changes in crude oil and natural gas pricing, production volumes, foreign exchange rates, and capital and operating costs.

2006 Overview

- Combined oil sands and natural gas production in 2006 was 294,800 barrels of oil equivalent (boe) per day, compared to 206,100 boe per day in 2005. Oil sands production averaged 260,000 bpd in 2006 (253,800 bpd of synthetic crude oil and 6,200 bpd of bitumen sold directly to the market), compared to 171,300 bpd in 2005. Natural gas production averaged 191 million cubic feet (mmcf) per day, compared to an average 190 mmcf per day in 2005.
- Oil sands cash operating costs averaged $21.70 per barrel during 2006 compared to $24.55 per barrel in 2005. The decrease in 2006 was primarily due to fixed operating costs being spread over higher production volumes, as well as lower natural gas costs.
- Suncor continued to make progress on the addition of the coker unit to Upgrader 2. At year-end, construction was approximately 70% complete. The project remains on schedule and within budget.
- Average daily in-situ bitumen production from Suncor's Firebag facilities increased to 33,700 bpd in 2006 from 19,100 bpd in 2005.
- Plans for Suncor's next major stage of oil sands growth were also advanced in 2006 with receipt of regulatory approval for a planned third upgrader, a key component in the company's Voyageur Strategy to increase production to 500,000 to 550,000 bpd in 2010 to 2012.
- In its U.S. downstream operations, Suncor completed modifications in June to the company's Commerce City refining operation that enabled production of ultra low sulphur diesel fuel and the integration of up to 15,000 bpd of oil sands sour crude into the refinery's feedstock.
- In Suncor's Canadian downstream operations, modifications were completed in July to enable the company's Sarnia refinery to meet ultra low sulphur diesel requirements. The second stage of this project, slated for completion in the fourth quarter of 2007, is planned to integrate up to 40,000 bpd of oil sands sour crude into the facility's feedstock and to improve the economic performance of the refinery.
- While continuing to expand its integrated oil sands and downstream refining and marketing businesses, Suncor also made advances in its renewable energy strategy with the opening of Canada's largest ethanol plant and the commissioning of its third wind farm. Further investment in ethanol-based biofuels and a fourth wind farm are planned for 2007.
- Maintaining a strong balance sheet remained a priority in 2006. Suncor's net debt (short and long-term debt less cash and cash equivalents) at December 31, 2006, was $1.9 billion (approximately 0.4 times cash flow from operations). Year-end net debt in 2005 was $2.9 billion (approximately 1.2 times cash flow from operations).
- Suncor achieved a company-wide return on capital employed of 40.6% in 2006 (excluding capitalized costs for major projects in progress), compared to 19.7% in 2005. Including capitalized costs related to major projects in progress, return on capital employed was 30.4% in 2006, and 14.3% in 2005.

Selected financial information

Annual Financial Data

Year ended December 31 ($ millions except per share data)	**2006**	2005	2004
Revenues	**15 829**	11 129	8 705
Net earnings	**2 971**	1 158	1 076
Total assets	**18 781**	15 149	11 774
Long-term debt	**2 385**	3 007	2 217
Dividends on common shares	**127**	102	97
Net earnings attributable to common shareholders per share – basic	**6.47**	2.54	2.38
Net earnings attributable to common shareholders per share – diluted	**6.32**	2.48	2.33
Cash dividends per share	**0.30**	0.24	0.23

Outstanding Share Data

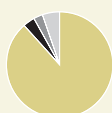
As at December 31, 2006 (thousands)	
Number of common shares	459 944
Number of common share options	19 809
Number of common share options – exercisable	8 627

Quarterly Financial Data

	2006				2005			
	Quarter ended				Quarter ended			
($ millions except per share)	**Dec. 31**	**Sept. 30**	**June 30**	**Mar. 31**	Dec. 31	Sept. 30	June 30	Mar. 31
Revenues	**3 787**	**4 114**	**4 070**	**3 858**	3 521	3 149	2 385	2 074
Net earnings	**358**	**682**	**1 218**	**713**	693	315	83	67
Net earnings attributable to common shareholders per share								
Basic	**0.78**	**1.48**	**2.65**	**1.56**	1.52	0.69	0.18	0.15
Diluted	**0.76**	**1.45**	**2.59**	**1.52**	1.48	0.67	0.18	0.14

Net Earnings (1)

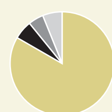
Year ended December 31,
($ millions)



	06	05	04
Oil Sands	**2 824**	976	970
Natural Gas	**109**	155	115
Energy Marketing and Refining – Canada	**86**	41	80
Refining and Marketing – U.S.A.(3)	**168**	142	34

Cash Flow from Operations (1)

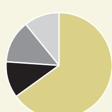
Year ended December 31,
($ millions)



	06	05	04
Oil Sands	**3 902**	1 878	1 734
Natural Gas	**281**	412	319
Energy Marketing and Refining – Canada	**217**	152	188
Refining and Marketing – U.S.A.(3)	**281**	247	59

Capital Employed (1) (2)

Year ended December 31,
($ millions)



	06	05	04
Oil Sands	**5 092**	4 472	4 105
Natural Gas	**861**	563	448
Energy Marketing and Refining – Canada	**1 023**	486	512
Refining and Marketing – U.S.A.(3)	**831**	327	232

(1) Excludes Corporate and Eliminations segment.
(2) Excludes major projects in progress.
(3) Refining and Marketing – U.S.A. 2006 and 2005 data includes results of the former Colorado Refining Company, acquired May 31, 2005.

Fluctuations in quarterly net earnings for 2006 and 2005 were due to a number of factors:

- Significantly higher Oil Sands production and sales volumes during 2006, following the September 2005 completion of recovery work to repair portions of the facilities damaged in the January 2005 fire, and the subsequent expansion of synthetic crude oil production capacity (to 260,000 bpd from 225,000 bpd).
- Changes in U.S. dollar denominated crude oil and natural gas prices. WTI averaged US$66.20 per barrel (bbl) in 2006 compared to US$56.55/bbl in 2005, and Henry Hub natural gas prices averaged US$7.25/mcf in 2006, compared to US$8.55/mcf in 2005.
- Cash operating costs varied due to variations in Oil Sands production levels, the timing and amount of maintenance activities, increased insurance expenses, and the price and volume of natural gas used for energy in Oil Sands operations.
- Alberta Oil Sands Crown royalties fluctuated as a result of changes in crude oil commodity prices and the extent and timing of annual capital and operating expenditures.
- Commodity and refined product prices fluctuated as a result of global and regional supply and demand, as well as seasonal demand variations. In our downstream operations, seasonal prices have historically reflected higher demand for vehicle fuels and asphalt in summer and heating fuels in winter, although 2006 saw these variations reduced significantly. Improved refining margins in 2006 compared to 2005 were partially offset by decreasing retail margins resulting from competitive market conditions.
- Realized commodity prices were unfavourably impacted by continued increases in the 2006 and 2005 average Cdn$/US$ exchange rates, which reduced the Canadian dollar revenues earned. The minimal increase in the year-end exchange rate resulted in no net foreign exchange gains for the U.S. dollar denominated debt in 2006, after a $37 million pretax gain in 2005.
- Reductions in both the federal and Alberta provincial corporate tax rates during the second quarter of 2006 increased 2006 net earnings by $419 million.
- The timing and amount of insurance receipts in both 2006 and 2005 related to the 2005 Oil Sands fire.

Consolidated Financial Analysis

This analysis provides an overview of our consolidated financial results for 2006 compared to 2005. For a detailed analysis, see the various business segment analyses.

Net Earnings

Our net earnings were $2.971 billion in 2006, compared with $1.158 billion in 2005 (2004 – $1.076 billion). The increase was primarily due to higher Oil Sands production coupled with increased U.S. dollar benchmark crude oil prices, strong refining margins in our downstream operations, and the substantive enactment of both federal and Alberta provincial income tax rate reductions in 2006. These positive impacts were partially offset by higher royalty expenses, increased maintenance and labour expenses, and additional third party insurance premium during 2006. The impact of a stronger Canadian dollar also reduced the sales value of Suncor's U.S. dollar denominated products.

Net Earnings Components (1)

Year ended December 31 ($ millions, after-tax)	**2006**	2005	2004
Net earnings before the following items:	**2 333**	838	969
Firebag in-situ start-up costs	**(13)**	(4)	(14)
Oil Sands fire accrued insurance proceeds (2)	**232**	293	—
Impact of income tax rate reductions on opening net future income tax liabilities	**419**	—	53
Unrealized foreign exchange gains on U.S. dollar denominated long-term debt	**—**	31	68
Net earnings as reported	**2 971**	1 158	1 076

(1) This table explains 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 unless otherwise noted)	**2006**	2005	2004
West Texas Intermediate (WTI) crude oil US$/barrel at Cushing	**66.20**	56.55	41.40
Canadian 0.3% par crude oil Cdn$/barrel at Edmonton	**73.05**	69.00	52.55
Light/heavy crude oil differential US$/barrel WTI at Cushing less Lloydminster Blend at Hardisty	**21.85**	20.90	13.55
Natural gas US$/thousand cubic feet (mcf) at Henry Hub	**7.25**	8.55	6.20
Natural gas (Alberta spot) Cdn$/mcf at AECO	**7.00**	8.50	6.80
New York Harbour 3-2-1 crack US$/barrel (1)	**9.80**	9.50	6.90
Ontario refined product demand percentage change over prior year (2)	**(1.6)**	0.1	4.3
Colorado light product demand percentage change over prior year (3)	**2.2**	2.5	7.2
Exchange rate: Cdn$/US$	**0.88**	0.83	0.77

(1) New York Harbour 3-2-1 crack is an industry indicator measuring the margin on 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.

(2) Figures for 2004 and 2005 are based on published government data. Figure for 2006 is an internal estimate based on preliminary government data.

(3) Figures for 2004 and 2005 are based on public reporting by state and government agencies. The 2006 figure is based on consensus estimates by third party consultants.

Revenues were $15.8 billion in 2006, compared with $11.1 billion in 2005 (2004 – $8.7 billion). Excluding the impact of net insurance proceeds related to the January 2005 fire at our Oil Sands operations, the increase was primarily due to the following:

- Production and sales volumes increased significantly during 2006, reflecting the October 2005 production capacity expansion to 260,000 bpd from 225,000, and the completion of recovery work from damage caused by the January 2005 fire.
- Average crude oil prices were higher in 2006 than in 2005. A 17% increase in average U.S. dollar WTI benchmark prices increased the selling price of Oil Sands crude oil production. This was partially offset by a 5% widening of the average light/heavy crude oil differentials compared to the WTI benchmark index. A 6% increase in the average Cdn$/US$ exchange rate resulted in lower realizations on our crude oil sales basket. Because crude oil is primarily sold based on U.S. dollar benchmark prices, a narrowing of the exchange rate difference produced a corresponding reduction in the Canadian dollar value of our products.
- Refined product wholesale prices in both EM&R and R&M were higher due to higher crude oil benchmark prices. In addition, 2006 reflects a full year of refined product sales volumes in R&M attributable to our acquisition of the Colorado Refining Company in the second quarter of 2005.
- The absence of strategic crude oil hedging losses in 2006 increased revenues by $535 million. During 2005, we sold 36,000 bpd of our crude oil production at an average fixed price of US$23/bbl. These hedges expired at December 31, 2005.
- Energy marketing and trading revenues increased to $1,582 million in 2006 compared to $827 million in 2005. The increase is due primarily to increased physical trading activities and higher average commodity prices. The results of energy marketing and trading are evaluated net of energy marketing and trading expenses. For a discussion of these net results, see page 33.

Partially offsetting these increases were the following:

- Retail prices in both EM&R and R&M reflected increasingly competitive pricing markets in the Ontario and Colorado regions.
- Lower price realizations on natural gas. Realized natural gas prices were $7.15 per thousand cubic feet (mcf) in 2006 compared to $8.57 per mcf in 2005, reflecting lower benchmark commodity prices.

Overall, increased production in our Oil Sands operations increased revenues by approximately $2.2 billion; higher crude oil prices, net of the impact of the higher average Cdn$/US$ exchange rate, increased total revenues by approximately $745 million; and the absence of hedging losses increased revenues by approximately $535 million.

Purchases of crude oil and products were $4.7 billion in 2006 compared with $4.2 billion in 2005 (2004 – $2.9 billion). The increase was primarily due to the following:

- Higher benchmark crude oil prices. This had the largest impact on product purchases for EM&R and R&M as WTI increased 17% over the prior year.
- Increased purchases of crude oil feedstock and refined products to meet sales commitments during planned maintenance shutdowns in both EM&R and R&M, and to more fully utilize the additional refining capacity acquired by R&M in the second quarter of 2005.
- Additional purchases of crude oil and products to meet plant and customer demands associated with unplanned maintenance at our Oil Sands operations.

Operating, selling and general expenses were $3.0 billion in 2006 compared with $2.4 billion in 2005 (2004 – $2.0 billion). The primary reasons for the increase were:

- An increase in the costs associated with planned and unplanned maintenance activities and labour costs.
- Higher stock-based compensation expenses as a result of the increase in our share price.

Transportation and other costs were $212 million in 2006 compared to $152 million in 2005 (2004 – $132 million). The increase in transportation costs was primarily due to increased volumes shipped out of the Fort McMurray area, and the increased shipments of Oil Sands sour crude blends to the U.S. Gulf Coast market.

Depreciation, depletion and amortization (DD&A) was $695 million in 2006, compared to $568 million in 2005 (2004 – $514 million). DD&A at Oil Sands increased by $55 million, primarily due to the inclusion of newly commissioned upgrading facilities and Firebag Stage 2 operations in our depreciable cost base during the fourth quarter of 2005. The DD&A for EM&R and R&M increased by $21 million and $15 million respectively in 2006 as a result of the completion of capital projects during the year, and the inclusion of these costs in our depreciable cost base. The capital projects for both EM&R and R&M were facility upgrades to enable production of ultra low sulphur diesel, in addition to the new ethanol facility completed in EM&R.

Royalty expenses were $1,038 million in 2006 compared with $555 million in 2005 (2004 – $531 million). The increase in 2006 was primarily due to increased Oil Sands royalties reflecting higher sales volumes, and higher price realizations. For a discussion of Oil Sands Crown royalties, see page 29.

Taxes other than income taxes were $595 million in 2006 compared to $529 million in 2005 (2004 – $540 million). The increase was primarily due to higher sales volumes subject to fuel excise taxes in our Oil Sands operations.

Financing expenses were $39 million in 2006 compared with income of $15 million in 2005 (2004 – expenses of $24 million). The increase in financing expenses was primarily due to the absence of any offsetting foreign exchange gains on our U.S. dollar denominated long-term debt. Interest expense on long-term debt was consistent with the prior year, with the impact of higher interest rates offset by lower debt levels. Total interest expense, net of capitalized interest, was $21 million in 2006 compared to $32 million in 2005. Capitalized interest was $129 million in 2006 compared to $119 million in 2005.

Income tax expense was $835 million in 2006 (22% effective tax rate), compared to $694 million in 2005 (37% effective tax rate) and $526 million in 2004 (33% effective tax rate). Income tax expense in both 2006 and 2004 included the effects of reductions in federal and Alberta provincial tax rates that reduced opening future income tax liabilities as follows:

Impact of Tax Rate Changes on Segmented Earnings

($ millions, increase (decrease) in earnings)	Oil Sands	Natural Gas	Energy Marketing & Refining – Canada	Corporate	**2006 Total**	2005 Total	2004 Total
Federal	290	36	5	(39)	**292**	—	—
Provincial	139	17	—	(29)	**127**	—	53
	429	53	5	(68)	**419**	—	53

Excluding these adjustments, income tax expense in 2006 was $1,254 million (33% effective tax rate) and $579 million in 2004 (36% effective tax rate).

Corporate Expenses

After-tax net corporate expenses were $216 million in 2006 compared to $156 million in 2005 (2004 – $123 million). Excluding the impact of group elimination entries, actual after-tax net corporate expenses were $222 million in 2006 (2005 – $167 million; 2004 – $111 million). The increase in net expenses resulted primarily from additional future tax expense as a result of the revaluation of future income taxes, higher stock-based compensation expenses and an increase in DD&A relating to our new enterprise resource planning system implemented throughout 2006. These factors were partially offset by the elimination of the self-insurance entity premium expense (fully offset in our Oil Sands segment). Corporate had a net cash deficiency of $443 million in 2006, compared with $105 million in 2005 (2004 – $325 million). The additional deficiency in 2006 was primarily due to changes in working capital.

Breakdown of Net Corporate Expense

Year ended December 31, ($ millions)	**2006**	2005	2004
Corporate expenses	**222**	167	111
Group eliminations	**(6)**	(11)	12
Total	**216**	156	123

Consolidated Cash Flow from Operations

Cash flow from operations was $4.533 billion in 2006 compared to $2.476 billion in 2005 (2004 – $2.013 billion). The increase in cash flow from operations was primarily due to the same factors that impacted net earnings, with the exception of DD&A, foreign exchange gains on our U.S. dollar denominated long-term debt in 2005, and future income taxes, all of which are non-cash items.

Dividends

Total dividends paid during 2006 were $0.30 per share, compared with $0.24 per share in 2005 (2004 – $0.23 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. In the second quarter of 2006, the Board approved an increase in the quarterly dividend to $0.08 per share from $0.06 per share.

Liquidity and Capital Resources

At December 31, 2006, our capital resources consisted primarily of cash flow from operations and available lines of credit. Our level of earnings and cash flow from operations depends on many factors, including commodity prices, production/sales levels, downstream margins, operating expenses, taxes, royalties, and Cdn$/US$ exchange rates.

At December 31, 2006, our net debt was approximately $1.9 billion compared to $2.9 billion at December 31, 2005. The decrease in debt levels was primarily a result of higher cash flow from operations.

In 2006, the following changes to our available credit facilities were completed:

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

Our undrawn lines of credit at December 31, 2006, were approximately $1.8 billion. Suncor's current long-term senior debt ratings are A- by Standard & Poor's, A(low) by Dominion Bond Rating Service and A3 by Moody's Investors Service. All debt ratings have a stable outlook.

Interest expense on debt continues to be influenced by the composition of our debt portfolio, and we are benefiting from short-term floating interest rates continuing at low levels. To manage fixed versus floating rate exposure, we have entered into interest rate swaps with investment grade counterparties, resulting in the swapping of $600 million of fixed rate debt to variable rate borrowings.

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

We believe we have the capital resources to fund our 2007 capital spending program of $5.3 billion and to meet current working capital requirements. If additional capital is required, we believe adequate additional financing is available at commercial terms and rates.

We anticipate our growth plan will be financed from internal cash flow, which is dependent on commodity prices and production levels, as well as debt. We plan to continue to evaluate strategic crude oil hedging opportunities to provide downside protection against adverse changes in commodity prices (See page 31 for a discussion of our crude oil hedging program). After 2006, to support our growth strategy and sustain operations, we are projecting an annual capital spending program of approximately $5 billion. Actual spending is subject to change due to such factors as internal and external approvals and capital availability. Refer to the discussion under Risk Factors Affecting Performance on page 30 for additional factors that can have an impact on our ability to generate funds to support investing activities.

During the fourth quarter of 2006, we received the final settlement of our property damage claim related to the January 2005 Oil Sands fire.

Effective May 15, 2006, our primary business interruption insurer discontinued operations. During the third quarter 2006, we recorded additional premium expenses related to losses incurred by this insurer primarily relating to hurricane activity in the Gulf of Mexico during the summer of 2005.

Aggregate Contractual Obligations and Off-balance Sheet Financing

		Payments Due by Period			
($ millions)	Total	2007	2008-09	2010-11	Later Years
Fixed-term debt, commercial paper (1)	2 347	681	—	500	1 166
Capital leases	38	1	3	3	31
Interest payments on fixed-term debt, commercial paper and capital leases (1)	2 393	144	222	224	1 803
Employee future benefits (2)	565	40	90	104	331
Asset retirement obligations (3)	1 657	104	175	96	1 282
Non-cancellable capital spending commitments (4)	216	216	—	—	—
Operating lease agreements, pipeline capacity and energy services commitments (5)	5 346	279	577	574	3 916
Total	**12 562**	**1 465**	**1 067**	**1 501**	**8 529**

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 resold shortly after purchase, are one example of excluded items.

(1) Includes $2,066 million of U.S. and Canadian dollar denominated debt that is redeemable at our option. Maturities range from 2007 to 2034. Interest rates vary from 5.95% to 7.15%. We entered into various interest rate swap transactions maturing in 2007 and 2011 that resulted in an average effective interest rate in 2005 ranging from 5.2% to 6.0% on $600 million of our medium-term notes. Approximately $280 million of commercial paper with an effective interest rate of 4.3% was issued and outstanding at December 31, 2006.

(2) Represents the undiscounted expected funding by the company to its pension plans as well as benefit payments to retirees for other post-employment 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 $216 million at the end of 2006. In addition to capital projects, we spend maintenance capital to sustain our current operations. In 2007, we anticipate spending approximately $900 million at our Oil Sands operations 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.

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.

In addition, a very limited number of our commodity purchase agreements, off-balance sheet arrangements (for a discussion of these arrangements see page 28) 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.

At December 31, 2006, we were in compliance with all covenants and our debt ratings were investment grade with a stable outlook. For more information, see page 25.

Significant Capital Project Update

We spent $3.5 billion on capital investing activities in 2006 compared to $2.7 billion ($3.1 billion including the cost of the fire rebuild and capitalized interest) in 2005 (2004 – $1.7 billion). The projects listed below represent the significant individual capital projects underway to support both our growth and sustaining capital needs. For a discussion of our Oil Sands growth strategy, refer to page 46. All projects listed below have received Board of Directors approval.

Description	Cost Estimate ($ millions)[1]	Spent in 2006 ($ millions)	Total Spent to Date ($ millions)	Status[1]
Oil Sands				
Coker unit[2]	2 100	665	1 590	Project is on schedule and on budget.
Millennium naphtha unit[3]	650	80	85	Project is on schedule and on budget.
Steepbank extraction plant[4]	880	55	65	Project is on schedule and on budget.
Firebag cogeneration and expansion	400	190	315	Project is on schedule and on budget.
EM&R				
Diesel desulphurization and oil sands integration	960	320	800	Project is on schedule; and cost estimate has been revised from the April 2005 estimate of $800 million.[5]
R&M				
Diesel desulphurization and oil sands integration	540 (US$445)	115 (US$95)	530 (US$435)	Project complete.[6]

(1) Estimating and budgeting for major capital projects is a process that involves uncertainties and that evolves in stages, each with progressively more refined data and a correspondingly narrower range of uncertainty. At very early stages, when broad engineering design specifications are developed, the level of uncertainty can result in price ranges with -30%/+50% (or similar) levels of uncertainty. As project engineering progresses, vendor bids are studied, goods and materials ordered and we move closer to the build stage, the level of uncertainty narrows. Generally, when projects receive final approval from our Board of Directors, our cost estimates have a range of uncertainty that has narrowed to the -10%/+10% or similar range. The projects noted in the above table have cost estimates within this range of uncertainty. These ranges establish an expected high and low capital cost estimate for a project. When we say that a project is "on budget," we mean that we still expect the final project capital cost to fall within the current range of uncertainty for the project. Even at this stage, the uncertainties in the estimating process and the impact of future events, can and will cause actual results to differ, in some cases materially, from our estimates.

(2) Excludes costs associated with bitumen feed.

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

(4) The Steepbank extraction plant will replace and enhance existing base plant extraction facilities.

(5) See page 52 for discussion.

(6) In the first quarter of 2006, the project budget was increased to a final expected cost of US$445 million from then-current estimates of US$390 million. The original cost estimate was US$300 million.

The addition of a third upgrader has not yet been approved by Suncor's Board of Directors. Suncor has not yet announced firm capital cost estimates for this project as the cost estimate, together with the final configuration of the project, is still under development. However, preliminary figures including those in Suncor's regulatory approval application are under upward pressure. Detailed engineering is expected in 2007, at which time final approval to proceed with the project will be considered by Suncor's Board of Directors. Subject to Board approval, the project will be included in the above table at that time.

To date approximately $900 million has been approved for planning and scoping initiatives related to project design for the third upgrader.

Suncor's Firebag Stage 3 project is expected to be submitted for final Board of Director's approval in 2007. To date approximately $550 million has been approved for planning and scoping initiatives related to project design.

Variable Interest Entities and Guarantees and Off-balance Sheet Arrangements

At December 31, 2006, we had off-balance sheet arrangements with Variable Interest Entities (VIEs), and indemnification agreements with other third parties, as described below.

We have a securitization program in place to sell, on a revolving, fully serviced and limited recourse basis, up to $170 million (2005 – $340 million) of accounts receivable having a maturity of 45 days or less, to a third party. The third party is a multiple party securitization vehicle that provides funding for numerous asset pools. As at December 31, 2006, $170 million (2005 – $340 million) in outstanding accounts receivable had been sold under the program. Although the company does not believe it has any significant exposure to credit losses, under the recourse provisions, we provided indemnification against potential credit losses for certain counterparties. This indemnification did not exceed $72 million in 2006 and no contingent liability or earnings impact have been recorded for this indemnification as we believe we have 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, 2006, were $170 million and approximately $623 million, respectively. We recorded an after-tax loss of approximately $2 million on the securitization program in 2006 (2005 – $4 million; 2004 – $2 million).

In 1999, we entered into an equipment sale and leaseback arrangement with a VIE for proceeds of $30 million. The VIE's sole asset was the equipment sold to it and leased back by Suncor. 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, 2006, the VIE did not have any assets or liabilities.

We have agreed to indemnify holders of the 7.15% fixed-term U.S. dollar notes, the 5.95% fixed-term U.S. dollar notes and our credit facility lenders for added costs related to taxes, assessments or other government charges or conditions, including any required withholding amounts. Similar indemnity terms apply to the receivables securitization program, and certain facility and equipment leases.

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

Outlook

During 2007, management will focus on the following operational priorities:

- Achieve annual oil sands production (including bitumen sold directly to the market) of 260,000 to 270,000 bpd with a cash operating cost average of $21.50 to $22.50 per barrel. Steady and reliable production will help us manage cash operating costs.
- Increase natural gas production (including natural gas liquids and crude oil) to an average 215 to 220 mmcf equivalent per day. We expect to bring several existing wells into production and will continue to focus on high-volume deep gas prospects in 2007.
- Advance plans for increased bitumen supply. Launch the regulatory, consultation and engineering work required to determine mine development potential for Voyageur South (Lease 23), receive Board of Director approval for our Firebag Stage 3 in-situ development, including cost estimates.
- Safely complete all planned expansion tie ins. Complete a 50-day shutdown on Upgrader 2 to perform planned maintenance and tie in expanded facilities that are expected to increase production to 350,000 bpd in 2008. At the Sarnia refinery, complete a 65-day shutdown to tie in new and modified equipment to allow the processing of up to 40,000 bpd of oil sands sour crude.
- Advance plans for increased upgrader capacity. Complete the Engineering Design Study (EDS) phase, which is necessary to seek Board of Directors approval to proceed with construction of our planned third oil sands upgrader, a key component of achieving more than half a million bpd by 2010 to 2012.
- Continue to improve safety performance.
- Focus on enterprise-wide efficiency. For example, improved operational reliability is the goal of establishing a single-vendor, performance-based maintenance contract for all Canadian facilities.
- Maintain a strong balance sheet. With capital spending plans of more than $5 billion, a strong balance sheet will be critical. Suncor is targeting debt at a maximum of two times cash flow.

- Continue to pursue energy efficiencies, greenhouse gas offsets and new, renewable energy projects. We plan to continue investment in biofuels and to commission our fourth – and largest yet – joint venture wind power project in 2007. Complete the stakeholder consultation and preliminary engineering needed to determine feasibility of expanding the St. Clair Ethanol facility.

Oil Sands Crown Royalties and Cash Income Taxes

Under the current Province of Alberta oil sands royalty regime, Alberta Crown royalties for oil sands projects are payable at the rate of 25% of the difference between a project's annual gross revenues net of related transportation costs (R), less allowable costs including allowable capital expenditures (the R-C Royalty), subject to a minimum royalty, currently at 1% of R. The Alberta government has classified Suncor's current Oil Sands operations as two distinct "projects" for royalty purposes: Suncor's base oil sands mining and associated upgrading operations with royalties based on upgraded product values, and the current Firebag in-situ project with royalties based on bitumen values under the government's generic bitumen-based royalty regime for oil sands projects.

In 1997, Suncor was granted an option by the government to transition our base operations on January 1, 2009, to the generic bitumen-based royalty regime, subject to finalizing certain terms of transition. Suncor and the government reached agreement on the terms and conditions of our option in the third quarter of 2005. In November 2006, we exercised our option to convert to the bitumen-based royalty. As a result, starting January 1, 2009, we expect to pay a royalty in respect of our base operations of 25% of R-C, with "R" based on bitumen rather than upgraded product values, and "C" excluding substantially all of the upgrading costs.

In 2006, the Department of Energy proposed a new methodology for determining the "R" related to bitumen using an synthetic crude oil (SCO) value less an upgrading processing cost of service charge. This methodology would generally result in higher attributed bitumen values than those used under the current formula. The Crown is consulting with industry, with a decision on the methodology anticipated by January 1, 2008.

A new bitumen pricing methodology is not expected to affect base operation royalties until our transition to the bitumen-based regime effective January 1, 2009. However, for our Firebag operations the pricing methodology could be retroactively applied to November 1, 2003, when Firebag commenced production. The outcome of this review is uncertain, and future royalties payable as well as the determination of net reserves may be affected.

In addition, the Government of Alberta has announced a review of its Crown royalties, to be completed by the summer of 2007.

Assuming anticipated levels of operating expenses and capital expenditures for each project remain relatively constant, and there are no changes to the current Government of Alberta oil sands royalty regime or the government's application of the applicable rules (including no changes to the bitumen pricing methodology), and no other unanticipated events occur, we believe future variability in Oil Sands royalty expense will primarily be a function of changes in annual Oil Sands revenue. On that basis, we would generally expect Alberta Crown royalty expense for Oil Sands to range as set forth in the following chart. For years after 2008, this percentage range may decline as anticipated new in-situ production attracts royalties based on bitumen values at 1% until project payout. Although we have assumed there will be no change in the methodology for determining the price of bitumen used to determine "R," the methodology is not likely to be finalized until 2008, and as a result, the potential impacts are not currently known but may be material.

Anticipated Royalty Expense Based on Certain Assumptions

For the period from 2007-2012

WTI Price/bbl (US$)	40	50	60
Natural gas price per mcf at Henry Hub (US$)	6.75	8.25	10.00
Light/heavy oil differential of WTI at Cushing less Maya at the U.S. Gulf Coast (US$)	9.60	12.60	15.10
Cdn$/US$ exchange rate	0.80	0.85	0.90
Crown Royalty Expense % (based on percentage of total Oil Sands revenue)			
2007-2008 (all cases 2007 @ $50)	7-8	7-10	7-12
2009-2012 (1)	4-5	5-7	6-8

(1) During 2006, we exercised our option to transition our base operations in 2009 to the generic bitumen-based royalty regime.

The federal opposition parties and others have requested an elimination of the oil sands accelerated depreciation of capital costs incurred; however, to date no changes have been made. Assuming there are no changes to the current income tax regime for 2007, we estimate we will have partial cash taxes in the range of 70-100% of expected effective tax rates, based on current prices, and current forecasts of production, capital and operating costs for 2007. Any cash tax in 2007 would be due in February 2008. Assuming there are no changes to the current income tax regime, we do not expect any significant cash tax in subsequent years until the next decade, primarily due to the company's investment in the expansion of its oil sands operations to 500,000 to 550,000 bpd. In any particular year, our Oil Sands and Natural Gas operations may be subject to some cash income tax due to sensitivity to crude oil and natural gas commodity price volatility and the timing of recognition of capital expenditures for income tax purposes.

Alberta Crown royalties and cash taxes are highly sensitive to, among other factors, changes in crude oil and natural gas pricing, production volumes, foreign exchange rates, and capital and operating costs for each oil sands project. In addition, all aspects of the current Alberta oil sands royalty regime, including royalty rates and the royalty base, are subject to alteration by the Government of Alberta. Accordingly, in light of these uncertainties and the potential for unanticipated events to occur, we strongly caution that it is impossible to predict even a range of annualized royalty expense as a percentage of revenues or the impact royalties may have on our financial results, and actual differences may be material. The forward-looking information in the preceding paragraphs and table should not be taken as an estimate, forecast or prediction of future events or circumstances.

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

Climate Change

Our effort to reduce greenhouse gas emissions is reflected in our pursuit of greater internal energy efficiency, investment in renewable energy including wind power, carbon capture research and development, and emissions offsets.

We continue to consult with governments about the impact of the Kyoto Protocol and we plan to continue to actively manage our greenhouse gas emissions. As the announced Clean Air Act by the Conservative Government has been referred to a special committee for review and revision, the ultimate regulatory outcome is unknown. In the meantime, Suncor will continue to actively manage its air emissions, including greenhouse gases, and to advance opportunities such as carbon capture and geological sequestration, and renewable and alternate forms of energy such as wind power and biofuels.

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 and application of such legislation, stakeholder support for growth plans, extreme weather, regional labour issues and other issues discussed within Risk Factors for each of our business segments. As a company we identify risks in four principal categories: 1) Operational; 2) Financial; 3) Legal and Regulatory; and 4) Strategic. A more detailed discussion of our risk factors is presented in our most recent Annual Information Form/Form 40-F, filed with securities regulatory authorities. We are continually working to mitigate the impact of potential risks to our businesses. This process includes an entity wide risk review. The internal review is completed annually to ensure that all significant risks are identified and appropriately managed.

Commodity Prices, Refined Product Margins and Exchange Rates

Our future financial performance remains closely linked to hydrocarbon commodity prices, which can be influenced by many factors including global and regional supply and demand, seasonality, worldwide political events and weather. These factors, among others, can result in a high degree of price volatility. For example, from 2004 to 2006 the monthly average price for benchmark WTI crude oil ranged from a low of US$34.22/bbl to a high of US$74.46/bbl. During the same three-year period, the natural gas Henry Hub benchmark monthly average price ranged from a low of US$4.40/mcf to a high of US$14.07/mcf. We believe commodity price volatility will continue.

Crude oil and natural gas prices are based on U.S. dollar benchmarks that result in our realized prices being influenced by the Cdn$/US$ 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.

Changes to the Cdn$/US$ exchange rate relationship can create significant volatility in foreign exchange gains or losses. On the outstanding US$1 billion in debt at the end of 2006, a $0.01 change in the Cdn$/US$ exchange rate would change net earnings by approximately $11 million after-tax.

Future U.S. capital projects may be partially funded from Canadian operations. A weaker Canadian dollar would result in a higher funding requirement for these projects.

Sensitivity Analysis (1)

			Approximate Change in	
	2006 Average	Change	Cash Flow from Operations ($ millions)	After-tax Earnings ($ millions)
Oil Sands				
Price of crude oil ($/barrel) (2)	$68.03	US$1.00	82	55
Sweet/sour differential ($/barrel)	$8.84	US$1.00	37	25
Sales (bpd)	263 100	1 000	13	9
Natural Gas				
Price of natural gas ($/mcf) (2)	$7.15	0.10	5	4
Production/sales of natural gas (mmcf/d)	191	10	16	7
Consolidated				
Exchange rate: Cdn$/US$	0.88	0.01	43	29

(1) The sensitivity analysis shows the main factors affecting Suncor's annual cash flow from operations and earnings based on actual 2006 operations. The table illustrates the potential financial impact of these factors applied to Suncor's 2006 results. A change in any one factor could compound or offset other factors.

(2) Includes the impact of hedging activities.

Derivative Financial Instruments

We periodically enter into commodity-based derivative financial instruments such as forwards, futures, swaps, options and costless collars to hedge against the potential adverse impact of changing market prices due to variations in underlying commodity indices. In addition, we periodically enter into derivative financial instrument contracts such as interest rate swaps and foreign currency contracts as part of our risk management strategy to manage exposure to interest rate and foreign exchange fluctuations.

We also use energy derivatives, including physical and financial swaps, forwards and options to earn trading revenues. These trading activities are accounted for at fair value in our Consolidated Financial Statements.

Derivative contracts accounted for as hedges are not recognized in the Consolidated Balance Sheets. Realized and unrealized gains or losses on these contracts, including realized gains and losses on derivative hedging contracts settled prior to maturity, are recognized in earnings and cash flows when the related sales revenues, costs, interest expense and cash flows are recognized. See page 42 for a discussion of changes to the accounting for hedges effective January 1, 2007.

Gains or losses resulting from changes in the fair value of derivative contracts that do not qualify for hedge accounting are recognized in earnings and cash flows when those changes occur.

Commodity Hedging Activities Our 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.

To provide an element of stability to future earnings and cash flow, we resumed our strategic crude oil hedging program in the third quarter of 2005, receiving Board approval to fix a price or range of prices for up to approximately 30% of our total production of crude oil for specified periods of time. At December 31, 2006, we had entered into US$ WTI costless collar agreements covering 60,000 bpd of crude oil beginning January 1, 2007 and ending December 31, 2007, and 10,000 bpd from

January 1, 2008 to December 31, 2008. Prices for these barrels are fixed within a range from an average of US$51.64/bbl up to an average of US$101.06/bbl.

For collars, if market rates are within the range of the hedged contract prices, the option contracts making up the collar will expire with no exchange of cash. On settlement of swap agreements, our hedging contracts result in cash receipts or payments for the difference between the derivative contract and market rates for the applicable volumes hedged during the contract term. Such cash receipts or payments offset corresponding decreases or increases in our sales revenues or crude oil purchase costs. For accounting purposes, amounts received or paid on settlement are recorded as part of the related hedged sales or purchase transactions in the Segmented Statements of Earnings. In 2006, there was no net earnings impact due to crude oil hedging, compared to a decrease of $337 million in 2005 (2004 – decrease of $397 million).

Crude oil hedge contracts outstanding at December 31, 2006, were as follows:

Swap Transactions

	Quantity (bpd)	Average Price (US$/bbl)[(a)]	Revenue Hedged (Cdn$ millions)[(b)]	Hedge Period[(c)]
Costless collars	60 000	51.64 – 93.26	1 318 – 2 380	2007
Costless collars	10 000	59.85 – 101.06	255 – 431	2008

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

(b) The revenue hedged is translated to Cdn$ at the year-end exchange rate and is subject to change as the Cdn$/US$ exchange rate fluctuates during the hedge period.

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

Financial Hedging Activities 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.

We have entered into various interest rate swap transactions at December 31, 2006. 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	2006 Effective Interest Rate
Swap of 6.70% Medium Term Notes to floating rates	200	2011	5.2%
Swap of 6.80% Medium Term Notes to floating rates	250	2007	6.0%
Swap of 6.10% Medium Term Notes to floating rates	150	2007	5.3%

In 2006, these interest rate swap transactions reduced pretax financing expense by $6 million compared to a pretax reduction of $14 million in 2005 (2004 – $17 million pretax).

At December 31, 2006, we had also hedged €20.6 million in 2007 Euro exposure created by the anticipated purchase of equipment during the year.

Fair Value of Strategic Derivative Hedging Instruments The fair value of derivative hedging instruments is the estimated amount, based on broker quotes and/or internal valuation models, that we would receive (pay) to terminate the contracts. Such amounts, which also represent the unrecognized and unrecorded gain (loss) on the contracts, were as follows at December 31:

Fair Value of Hedging Derivative Financial Instruments

($ millions)	**2006**	2005
Revenue hedge swaps and collars	**22**	(4)
Margin hedge swaps	**—**	1
Interest rate and cross-currency interest rate swaps	**16**	22
Specific cash flow hedges of individual transactions	**(4)**	5
Total	**34**	24

Energy Marketing and Trading Activities In addition to the financial derivatives used for hedging activities, the company uses physical and financial energy contracts, including swaps, forwards and options to earn trading and marketing revenues. The financial trading activities are accounted for using the mark-to-market method and as such all financial instruments are recorded at fair value at each balance sheet date. Physical energy marketing contracts involve activities intended to enhance prices and satisfy physical deliveries to customers. The results of these activities are reported as revenue and as energy trading and marketing expenses in the Consolidated Statements of Earnings.

The net pretax earnings (loss) for the years ended December 31 were as follows:

Net Pretax Earnings (Loss)

($ millions)	**2006**	2005
Physical energy contracts trading activity	**41**	15
Financial energy contracts trading activity	**(3)**	5
General and administrative costs	**(3)**	(3)
Total	**35**	17

The fair value of unsettled financial energy trading assets and liabilities at December 31 was as follows:

Fair Value of Unsettled Financial Energy Trading Assets and Liabilities

($ millions)	**2006**	2005
Energy trading assets	**16**	82
Energy trading liabilities	**13**	70
Net energy trading assets	**3**	12

Change in Fair Value of Net Assets

($ millions)	**2006**
Fair value of contracts outstanding at December 31, 2005	12
Fair value of contracts realized during 2006	**(6)**
Fair value of contracts entered into during the period	**2**
Changes in values attributable to market price and other market changes	**(5)**
Fair value of contracts outstanding at December 31, 2006	**3**

The valuation of the above contracts was based on actively quoted prices and/or internal valuation models.

Counterparty Credit Risk 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 primarily with investment grade counterparties. Risk is also minimized through regular management review of the potential exposure to and credit ratings of such counterparties.

At December 31, the company had exposure to credit risk with counterparties as follows:

Counterparty Credit Risk

($ millions)	**2006**	2005
Derivative contracts not accounted for as hedges	**16**	82
Unrecognized derivative contracts accounted for as hedges	**35**	30
Total	**51**	112

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 major projects or undertaking significant changes to existing operations. Suncor's Oil Sands operating licence was temporarily extended in 2006 and we anticipate receipt of a new operating licence in 2007. In addition to these specific, known requirements, we expect future changes to environmental legislation, including anticipated legislation for air pollution (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 impacts of oil sands development in the Athabasca region
- Storage, treatment, and disposal of hazardous or industrial waste
- The need to reduce or stabilize various emissions to air and withdrawals and discharges to water
- Issues relating to global climate change, land reclamation and restoration
- Water use and water disposal
- Reformulated gasoline to support lower vehicle emissions.

Changes in environmental regulation could have a potentially adverse effect on us 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 cleanup costs and damages and the loss of important permits and licenses.

Another area of risk for Suncor and the oil sands industry 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 the CT technology and time to reclaim the tailings ponds could increase or decrease the current asset retirement cost estimates. We continue to monitor and assess other possible technologies and/or modifications to the CT process now being used.

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 of December 31, 2005 ($14 million as at December 31, 2005) as security for the estimated cost of our reclamation activity. Since there has been no production from Leases 86/17 in 2006, the amount of security remained unchanged.

For the Millennium and Steepbank mines, we have posted irrevocable letters of credit equal to approximately $163 million, representing security for the maximum reclamation liability in the period March 31, 2006 through March 31, 2007. For more information about our reclamation and environmental remediation obligations, refer to "Asset Retirement Obligations" under "Critical Accounting Estimates" in the "Suncor Overview and Strategic Priorities" section of our MD&A.

A new Mine Liability Management Program (MLMP) is under review by the Province of Alberta, and is currently planned for implementation June 30, 2007. The MLMP would involve increased reporting of progressive reclamation, measurement of MLMP assets against MLMP liabilities and measurement of reserve life. As currently proposed, initial security deposits for oil sands mining would be reduced. Partial security could be required if reclamation targets are not met and full security may eventually be required.

Regulatory Approvals

Before proceeding with most major projects, we must obtain regulatory approvals. The regulatory approval process can involve 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. We believe the following are the most critical accounting estimates used in the preparation of our consolidated financial statements.

Reserves Estimates

We are a Canadian issuer subject to Canadian reporting requirements, including rules in connection with the reporting of our reserves. However, we have received an exemption from Canadian securities administrators permitting us to report our reserves in accordance with U.S. disclosure requirements. Pursuant to U.S. disclosure requirements, we disclose net proved conventional oil and gas reserves, including natural gas reserves and bitumen reserves from our Firebag in-situ leases, using constant dollar cost and pricing assumptions. As there is no recognized posted bitumen price, these assumptions are based on a posted benchmark oil price, adjusted for transportation, gravity and other factors that create the difference ("differential") in price between the posted benchmark price and Suncor's bitumen. Both the posted benchmark price and the differential are generally determined as of a point in time, namely December 31 ("Constant Cost and Pricing"). Reserves from our Firebag in-situ leases are reported as barrels of bitumen, using these Constant Cost and Pricing assumptions (see "Required U.S. Oil and Gas and Mining Disclosure – Proved Conventional Oil and Gas Reserves" for net proved conventional oil and gas reserves).

Pursuant to U.S. disclosure requirements, we also disclose gross and net proved and probable mining reserves. The estimates of our gross and net mining reserves are based in part on the current mine plan and estimates of extraction recovery and upgrading yields. We report mining reserves as barrels of synthetic crude oil based on a net coker, or synthetic crude oil yield from bitumen of 80%. During 2005, we reached an agreement with the Government of Alberta finalizing the terms of our option to transition to the generic bitumen-based royalty regime commencing in 2009, allowing us to prepare an estimate of our net mining reserves. The estimate of our net mining reserves reflects the relative value of Alberta Crown and freehold royalty burdens under constant December 31 bitumen pricing and our exercise of the option to transfer to a bitumen-based Crown royalty effective the beginning of 2009 (See "Required U.S. Oil and Gas and Mining Disclosure – Proved and Probable Oil Sands Mining Reserves" for both gross and net, proved and probable mining reserves). Our Firebag in-situ leases are subject to Alberta Crown royalty based on bitumen, rather than synthetic crude oil (for a full discussion of our oil sands Crown royalties, see "Oil Sands Crown Royalties and Cash Income Taxes" on page 29).

In addition to required disclosure, our exemption issued by Canadian securities administrators permits us to provide further disclosure voluntarily. We provide this additional voluntary disclosure to show aggregate proved and probable oil sands reserves, including both mining reserves and reserves from our Firebag in-situ leases. In our voluntary disclosure we report our aggregate reserves on the following basis:

- Gross and net proved and probable mining reserves, on the same basis as disclosed pursuant to U.S. disclosure requirements (reported as barrels of synthetic crude oil based upon a net coker, or synthetic crude oil yield from bitumen of 80%); and
- Gross and net proved and probable bitumen reserves from Firebag in-situ leases, evaluated based on normalized constant dollar cost and pricing assumptions. Bitumen reserves estimated on this basis are subsequently converted, for aggregation purposes only, to barrels of synthetic crude oil based on a net coker or synthetic crude oil yield from bitumen of 80%.

Accordingly, our voluntary disclosures of reserves from our Firebag in-situ leases will differ from our required U.S. disclosure in three ways. Reserves from our Firebag in-situ leases under our voluntary disclosure:

(a) are disclosed on a gross basis as well as the required net basis under U.S. disclosure requirements;

(b) are converted from barrels of bitumen under U.S. disclosure requirements to barrels of synthetic crude oil for aggregation purposes only; and

(c) include proved plus probable reserves, rather than proved reserves only under U.S. disclosure requirements.

Under the U.S. disclosure requirements described above, our Firebag in-situ reserves were determined to be entirely uneconomic at December 31, 2004. In 2005, Constant Cost and Pricing assumptions were again applied to assess economic viability of our in-situ reserves. This assessment resulted in the rebooking of proved reserves at December 31, 2005. At December 31, 2006, pricing assumptions were again considered economically viable and our proved reserves disclosures reflect this. (See "Required U.S. Oil and Gas and Mining Disclosure – Proved Conventional Oil and Gas Reserves").

Under our voluntary disclosure, the year-end 2006 bitumen price determined pursuant to SEC pricing methodology was not materially different than the price determined pursuant to CSA Staff Notice 51-315. Consequently, for 2006 only one constant price scenario was used for year end disclosures. Refer to "Voluntary Oil Sands Reserves Disclosure – Estimated Gross and Net Proved and Probable Oil Sands Reserves Reconciliations."

Comparisons of reserve estimates under required U.S. Oil and Gas Mining Disclosure and Voluntary Oil Sands Reserve Disclosure may show material differences based on the pricing assumptions used, whether the reserves are reported as barrels of bitumen or barrels of synthetic crude oil, whether probable reserves are included, and whether the reserves are reported on a gross or net basis. These differences were more significant during 2004 and 2005 with considerably lower constant price assumptions. At December 31, 2006, there was no difference arising from pricing.

All of our reserves have been evaluated as at December 31, 2006, by independent petroleum consultants, GLJ Petroleum Consultants Ltd. (GLJ). In reports dated February 9, 2007 ("GLJ Oil Sands Reports"), GLJ evaluated our proved and probable reserves on our oil sands mining and Firebag in-situ leases pursuant to both U.S. disclosure requirements using Constant Cost and Pricing assumptions.

Estimates in the GLJ Oil Sands Reports consider recovery from leases for which regulatory applications have been submitted and no anticipated impediment to the receipt of regulatory approval is expected. The mining reserve estimates are based on a detailed geological assessment and also consider industry practice, drill density, production capacity, extraction recoveries, upgrading yields, mine plans, operating life and regulatory constraints.

For Firebag in-situ reserve estimates, GLJ considered similar factors such as our regulatory approval or likely impediments to the receipt of pending regulatory approval, project implementation commitments, detailed design estimates, detailed reservoir studies, demonstrated commercial success of analogous commercial projects and drill density. Our proved reserves are delineated to within 80 acre spacing with 3-D seismic control (or 40 acre spacing without 3-D seismic control) while our probable reserves are delineated to within 160 acre spacing without 3D seismic control. The major facility expenditures to develop our proved undeveloped reserves have been approved by our Board. Plans to develop our probable undeveloped reserves in subsequent phases are underway but have not yet received final approval from our Board.

In a report dated February 9, 2007 ("GLJ NG Report"), GLJ also evaluated our proved reserves of natural gas, natural gas liquids and crude oil (other than reserves from our mining leases and the Firebag in-situ reserves) as at December 31, 2006.

Our reserves estimates will continue to be impacted by both drilling data and operating experience, as well as technological developments and economic considerations.

Net reserves represent Suncor's 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 current Government of Alberta Royalty regime. These assumptions reflect market and regulatory conditions, as required, at December 31, 2006, 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.

Required U.S. Oil and Gas and Mining Disclosure

Proved and Probable Oil Sands Mining Reserves

	Oil Sands Mining Leases					
	Proved		Probable		Proved & Probable	
Millions of barrels of synthetic crude oil (1)	Gross (2)	Net (3)	Gross (2)	Net (3)	Gross (2)	Net (3)
December 31, 2005	1 528	1 440	896	862	2 424	2 302
Revisions of previous estimates	266	140	(262)	(298)	4	(158)
Extensions and discoveries	—	—	—	—	—	—
Production	(85)	(73)	—	—	(85)	(73)
December 31, 2006	**1 709**	**1 507**	**634**	**564**	**2 343**	**2 071**

(1) Synthetic crude oil reserves are based upon a net coker, or synthetic crude oil yield from bitumen of 80% (2005 – 80%).

(2) Our gross mining reserves are based in part on our current mine plan and estimates of extraction recovery and upgrading yields, rather than an analysis based on constant dollar or forecast pricing and cost assumptions.

(3) Net mining reserves reflect the value of Crown royalty burdens under constant December 31st pricing and incorporates our exercised option to elect to transfer to a bitumen-based Crown royalty effective at the beginning of 2009.

Proved Conventional Oil and Gas Reserves

The following data is provided on a net basis in accordance with the provisions of the Financial Accounting Standards Board's Statement No. 69 (Statement 69). This statement requires disclosure about conventional oil and gas activities only, and therefore our Oil Sands mining activities are excluded, while in-situ Firebag reserves are included.

Net Proved Reserves (1)

Crude Oil, Natural Gas Liquids and Natural Gas

Constant Cost and Pricing as at December 31	Oil Sands business: Firebag – crude oil (millions of barrels of bitumen) (2) (3) (4)	Natural Gas business: crude oil and natural gas liquids (millions of barrels)	Total (millions of barrels)	Natural Gas business: natural gas (billions of cubic feet)
December 31, 2005	632 (3)	7	639	449
Revisions on previous estimates (5)	(57)	—	(57)	5
Improved recovery (6)	340	—	340	—
Purchases of minerals in place	—	—	—	—
Extensions and discoveries	—	1	1	26
Production	(12)	(1)	(13)	(53)
Sales of minerals in place	—	—	—	(1)
December 31, 2006	**903**	**7**	**910**	**426**

(1) Our undivided percentage interest in reserves, after deducting Crown royalties, freehold royalties and overriding royalty interests. Our Firebag leases are only subject to Crown royalties.

(2) Although we are subject to Canadian disclosure rules in connection with the reporting of our reserves, we have received exemptive relief from Canadian securities administrators permitting us to report our proved reserves in accordance with U.S. disclosure practices.

(3) Estimates of proved reserves from our Firebag in-situ leases are based on Constant Cost and Pricing assumptions as at December 31. In 2004, due to unusually low year-end posted benchmark oil prices and unusually high year-end diluent prices, our proved reserves were determined to be uneconomic. Under 2005 Constant Cost and Pricing assumptions, we have rebooked our proved reserves, and these continue to be economically viable in 2006.

(4) We have the option of selling the bitumen production from these leases or upgrading the bitumen to synthetic crude oil. With the completion of upgrading expansion projects during 2005, all bitumen is expected to be processed into synthetic crude oil in the future, unless strategic market conditions exist.

(5) Natural gas infill drilling included in total revisions for 2006 was 11 billion cubic feet (bcf).

(6) Improved recovery recognizes a portion of our Firebag Stage 3 expansion project.

Voluntary Oil Sands Reserves Disclosure

Oil Sands Mining and Firebag In-situ Reserves Reconciliation

The following tables set out, on a gross and net basis, a reconciliation of our proved and probable reserves of synthetic crude oil from our Oil Sands mining leases and bitumen, converted to synthetic crude oil for comparison purposes only, from our in-situ Firebag leases, from December 31, 2005, to December 31, 2006, based on the GLJ Oil Sands Reports.

Estimated Gross Proved and Probable Oil Sands Reserves Reconciliation

	Oil Sands Mining Leases (1) (2)			Firebag In-situ Leases (1) (3)			Total Mining and In-situ (3)
Millions of barrels of synthetic crude oil (1)	Proved	Probable	Proved & Probable	Proved	Probable	Proved & Probable	Proved & Probable
December 31, 2005	1 528	896	2 424	561	2 137	2 698	5 122
Revisions of previous estimates	266	(262)	4	—	22	22	26
Improved recovery	—	—	—	252	(252)	—	—
Extensions and discoveries	—	—	—	—	—	—	—
Production	(85)	—	(85)	(10)	—	(10)	(95)
December 31, 2006	**1 709**	**634**	**2 343**	**803**	**1 907**	**2 710**	**5 053**

Estimated Net Proved and Probable Oil Sands Reserves Reconciliation

	Oil Sands Mining Leases (1) (2)			Firebag In-situ Leases (1) (3)			Total Mining and In-situ (3)
Millions of barrels of synthetic crude oil (1)	Proved	Probable	Proved & Probable	Proved	Probable	Proved & Probable	Proved & Probable
December 31, 2005	1 440	862	2 302	556	2 029	2 585	4 887
Revisions of previous estimates	140	(298)	(158)	(50)	(164)	(214)	(372)
Improved recovery	—	—	—	226	(226)	—	—
Extensions and discoveries	—	—	—	—	—	—	—
Production	(73)	—	(73)	(10)	—	(10)	(83)
December 31, 2006	**1 507**	**564**	**2 071**	**722**	**1 639**	**2 361**	**4 432**

(1) Synthetic crude oil reserves are based on a net coker, or synthetic crude oil yield from bitumen of 80% for reserves under Oil Sands Mining and under Firebag in-situ Leases. Although virtually all of our bitumen from the Oil Sands mining leases is upgraded into synthetic crude oil, we have the option of selling the bitumen produced from our Firebag in-situ leases and/or upgrading this bitumen into synthetic crude oil. Accordingly, these bitumen reserves are converted to synthetic crude oil for comparison purposes only.

(2) Our gross mining reserves are evaluated in part, based on the current mine plan and estimates of extraction recovery and upgrading yields, rather than an analysis based on constant dollar or forecast pricing assumptions. Net mining reserves reflect the relative value of Crown, freehold and overriding royalty burdens under constant December 31st pricing and reflects our exercised option to elect to transfer to a bitumen-based Crown royalty effective at the beginning of 2009.

(3) Under "Required U.S. Oil and Gas and Mining Disclosure," we reported proved reserves from our Firebag in-situ leases. The disclosure in the table above reports proved reserves from these leases and differs in the following three ways. Reserves from Firebag in-situ leases under our voluntary disclosure:

(a) are disclosed on a gross basis as well as the required net basis under required U.S. disclosure requirements;

(b) are converted from barrels of bitumen to barrels of synthetic crude oil in this table for aggregation purposes only; and

(c) include proved plus probable reserves, rather than proved reserves only under U.S. disclosure requirements. U.S. companies do not disclose probable reserves for non-mining properties. We voluntarily disclose our probable reserves for our Firebag in-situ leases as we believe this information is useful to investors, and allows us to aggregate our mining and in-situ reserves into a consolidated total for our Oil Sands business. As a result, our Firebag in-situ estimates in the above tables are not comparable to those made by U.S. companies.

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 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 measured at fair value and discounted to present value using a credit-adjusted risk-free discount rate of 5.5% (2005 – 5.6%). 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 entitled "Accretion of asset retirement obligations." Payments to settle the obligations occur on an ongoing basis and will continue over the lives of the operating assets, which can exceed 35 years. 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 Oil Sands and NG completed in the fourth quarter of 2006, we increased our estimated undiscounted total obligation to approximately $1.66 billion from the previous estimate of $1.22 billion. The increase was primarily due to a change in the Oil Sands estimate from $1.08 billion to $1.47 billion, primarily reflecting increased estimated costs related to tailings projects and increased land reclamation. The majority of the costs in Oil Sands are projected to occur over a time horizon extending to approximately 2060. In 2007, these changes in the ARO estimate are anticipated to result in additional after-tax expenses of approximately $19 million. The discounted amount of our ARO liability was $808 million at December 31, 2006, compared to $543 million at December 31, 2005.

The greatest area of judgment and uncertainty with respect to our asset retirement obligations relates to our Oil Sands mining leases where there is a requirement to provide for land productivity equivalent to pre-disturbed conditions. To reclaim tailings ponds, we are using a process referred to as consolidated tailings technology. At this time, no ponds have been fully reclaimed using this technology, although work is underway. The success and time to reclaim the tailings ponds could increase or decrease the current asset retirement cost estimates. The company continues to monitor and assess other possible technologies and/or modifications to the consolidated tailings process now being used.

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 Schedules of Segmented Data. 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. A 1% change in the assumptions at which pension benefits and other post-retirement benefit liabilities could be effectively settled is as noted below.

Employee Future Benefits Liability – Sensitivity Analysis

	Rate of Return on Plan Assets		Discount Rate		Rate of Compensation Increase	
($ millions)	1% Increase	1% Decrease	1% Increase	1% Decrease	1% Increase	1% Decrease
Increase (decrease) to net periodic benefit cost	(5)	5	(18)	21	9	(8)
Increase (decrease) to benefit obligation	—	—	(136)	161	35	(31)

Health care costs comprise a significant element of our post-retirement benefit obligation and is an area where there is increasing cost pressure due to an aging North American population. We have assumed a 9.5% annual rate of increase in the per capita cost of covered health care benefits for 2006, with an assumption that this rate will decrease by 0.5% annually, to 5% by 2015, and remain at that level thereafter.

A 1% change in the assumed health care cost trend rate would have the following effect:

($ 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)

Property, Plant and Equipment

We account for our Oil Sands in-situ and NG 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 more timely 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 exploratory dry hole costs are written off and reported as part of Oil Sands and NG exploration expenses in the Consolidated Statements of Earnings. 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 and/or adjustments in reserves. Such changes may require a test for the potential impairment of capitalized properties based on estimates of future cash flow from the properties. Estimates of future cash flows are subject to significant management judgment concerning oil and gas prices, production quantities and operating costs. Where management assesses that a property is fully or partially impaired, the book value of the property is reduced to fair value and either completely removed ("written off") or partially removed ("written down") in our records and reported as part of Oil Sands and NG DD&A expenses in the Consolidated Statements of Earnings.

Negative revisions in NG reserves estimates will result in an increase in depletion expenses.

The remainder of our plant and equipment are depreciated on a straight-line basis over the estimated useful life of the assets. The straight-line basis reflects asset usage as a function of time rather than production levels. For example, the useful life of plant and equipment at our Oil Sands base operations and our Firebag operations are not based on recorded reserves as we have access to other undeveloped properties, and bitumen feedstock from third parties, as well as the ability to provide processing services for other producers' bitumen. Firebag and NG property costs are depleted on a unit of production (UOP) basis. UOP amortization is used where that method better matches the asset utilization with the production associated with the asset. In each case, the expense is shown on the DD&A line in both the Consolidated Statements of Earnings and in the Schedules of Segmented Earnings.

We determine useful life based on prior experience with similar assets and, as necessary, in consultation with others who have expertise with the assets in question. However, the actual useful life of the assets may differ from our original estimate due to factors such as technological obsolescence, regulatory requirements and maintenance activity. As the majority of assets are depreciated on a straight-line basis, a 10% reduction in the useful life of plant and equipment would increase annual DD&A by approximately 10%. This impact would be reflected in all of our business segments with the majority of the impact being in Oil Sands.

We also continuously look at ways to further utilize technological advancements and opportunities for future growth. The classification of research and development costs as either capital or expense is dependent upon specific criteria, including production feasibility, available resources and management commitment.

Control Environment

Based on their evaluation as of December 31, 2006, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures (as defined in Rules 13(a)-15(e) and 15(d)-15(e) under the United States Securities Exchange Act of 1934 (the Exchange Act)) are effective to ensure that information required to be disclosed by us in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC rules and forms. In addition, other than as described below, as of December 31, 2006, there were no changes in our internal control over financial reporting that occurred during 2006 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. We will continue to periodically evaluate our disclosure controls and procedures and internal control over financial reporting and will make any modifications from time to time as deemed necessary.

During 2006, we largely completed the implementation of an enterprise resource planning (ERP) system in all of our businesses to facilitate our growth plan. We believe we took the necessary steps to monitor and maintain appropriate internal control over financial reporting during this transition period. These steps included deploying resources to mitigate internal control risks and performing additional verifications and testing to ensure data integrity.

The company has undertaken a comprehensive review of the effectiveness of its internal control over financial reporting as part of the reporting, certification and attestation requirements of Section 404 of the U.S. Sarbanes-Oxley Act of 2002. For the year ended December 31, 2006, the company's internal control over financial reporting was found to be operating free of any material weaknesses.

Change In Accounting Policies

Non-monetary Transactions

On January 1, 2006, the company prospectively adopted The Canadian Institute of Chartered Accountants (CICA) Handbook section 3831 "Non-monetary Transactions." The standard requires all non-monetary transactions to be measured at fair value (if determinable) unless future cash flows are not expected to change significantly as a result of a transaction or the transaction is an exchange of a product held for sale in the ordinary course of business. The company was required to record the effects of an existing contract at Oil Sands that exchanges off-gas produced as a by-product of the upgrading operations for natural gas. An equal amount of revenues for the sale of the off-gas and purchases of crude oil and products for the purchase of the natural gas are recorded. The amount of the gross up of revenues and purchases of crude oil and products for the year ended December 31, 2006 was $126 million.

Overburden Removal Costs

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

Recently Issued Canadian Accounting Standards

Financial Instruments/Other Comprehensive Income/Hedges

In 2005, the CICA approved Handbook section 3855 "Financial Instruments – Recognition and Measurement," section 1530 "Comprehensive Income" and section 3865 "Hedges." Effective January 1, 2007, these standards require the presentation of financial instruments at fair value on the balance sheet. These standards must be applied prospectively with an initial recognition adjustment to retained earnings and accumulated other comprehensive income.

For specific transactions identified as hedges, changes in fair value are recognized in net earnings or other comprehensive income based on the type and effectiveness of the individual instruments. Upon adoption of these standards the company's presentation will be more aligned with the current U.S. GAAP reporting as outlined in note 18 to the consolidated financial statements.

Other comprehensive income will represent the foreign currency translation of self-sustaining subsidiaries, the fair value gains/losses of specific financial investments (available for sale) and the effective portion of gains/losses of cash flow hedges. Presentation of other comprehensive income will require a change in the presentation of the Consolidated Statements of Earnings, and result in a new Statement of Comprehensive Income.

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

Financial assets	$26 million
Financial liabilities	$13 million
Retained earnings	$5 million
Cumulative foreign currency translation	$71 million
Accumulated other comprehensive loss	$63 million

No restatement of comparative balances is permitted.

The CICA has approved additional financial instrument and capital disclosure requirements. These new requirements will become effective on January 1, 2008.

Accounting Changes

In 2006, the CICA approved revisions to Handbook section 1506 "Accounting Changes." Effective January 1, 2007, accounting policy changes are permitted only in the event a change is made within a primary source of GAAP, or where a change is warranted to provide more relevant and reliable information. All accounting policy changes are to be applied retrospectively, unless impracticable. Any prior period errors identified also require retrospective application. The revised standards will not impact net earnings or financial position.

Stock-based Compensation

On July 6, 2006, the Emerging Issues Committee of the CICA approved an abstract (EIC 162) addressing the recognition of stock-based compensation expenses for employees eligible to retire prior to the vesting date of any award(s) issued. The abstract requires that the compensation expense be recognized over the term until the employee is eligible to retire, when earlier than the award vesting date. If the employee is eligible to retire at the time of grant, the award is to be expensed immediately. The abstract was applied retrospectively, effective December 31, 2006. No material adjustment was required in applying this standard.

Oil Sands

Located near Fort McMurray, Alberta, our Oil Sands business forms the foundation of our growth strategy 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 strategic sales of bitumen when market conditions are favourable.

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 that meet market demand.
- Increasing production capacity and improving reliability through staged expansion, continued focus on operational excellence and work site 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)	**2006**	2005	2004
Revenue	**7 407**	3 965	3 640
Production (thousands of bpd)	**260.0**	171.3	226.5
Average sales price ($/barrel)	**68.03**	53.81	42.28
Net earnings	**2 824**	976	970
Cash flow from operations (1)	**3 902**	1 878	1 734
Total assets	**13 692**	11 648	9 000
Cash used in investing activities	**2 230**	1 882	1 039
Net cash surplus (deficiency)	**2 098**	(274)	719
Sales mix (light/heavy mix)	**53/47**	54/46	63/37
Cash operating costs ($/barrel) (1)	**21.70**	24.55	15.15
ROCE (%) (2)	**53.7**	22.7	22.6
ROCE (%) (3)	**40.4**	16.3	18.5

(1) Non-GAAP measure. See page 58.

(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. See page 58.

(3) Includes capitalized costs related to major projects in progress. See page 58.

2006 Overview

- Oil Sands recorded significantly higher production and sales volumes during 2006, following the September 2005 completion of recovery work to repair portions of the facilities damaged in a January 2005 fire, and the subsequent expansion of synthetic crude oil production capacity (to 260,000 bpd from 225,000 bpd).
- In November, the Alberta Energy and Utilities Board (EUB) approved Suncor's application to build a third oil sands upgrader, designed to increase our production to 500,000 to 550,000 bpd in the 2010 to 2012 time frame. The EUB also conditionally approved our application to proceed with our proposed North Steepbank mine extension.

- Construction continued on the estimated $2.1 billion project that, when complete in 2008, is expected to increase upgrading capacity to 350,000 bpd. The centrepiece of this expansion is the addition of a third coker to Upgrader 2. The project remains on schedule and within budget projections. See page 27.
- Commercial operations for Stage 2 of our Firebag in-situ operations commenced as expected during the first quarter of 2006.
- In January 2007, Suncor commissioned new cogeneration facilities at its in-situ operations. A related expansion of in-situ production capacity is expected to be completed in 2007.

Analysis of Net Earnings

Net earnings were $2,824 million in 2006 compared to $976 million in 2005 (2004 – $970 million). The increase in net earnings was mainly the result of increased production and sales volumes reflecting the October 2005 production capacity expansion to 260,000 bpd and reduced production in 2005 as a result of the fire in January of that year, coupled with higher benchmark WTI prices in 2006. Net earnings also increased during 2006 as a result of the reduction of federal and Alberta provincial income tax rates. These positive impacts were partially offset by higher royalty expense resulting from higher net sales volumes and commodity prices, higher operating expenses, and increased insurance premium expense (a portion of which was paid to our self-insurance entity and is fully offset in the corporate segment with no impact on consolidated results).

Oil Sands average production was 260,000 bpd in 2006, compared to 171,300 bpd in 2005 (including bitumen sold to third parties). Sales volumes in 2006 averaged 263,100 bpd compared with 165,300 bpd in 2005. Higher sales volumes increased 2006 net earnings by $1,461 million. Production and sales volumes were significantly higher in 2006 due largely to the completion of recovery work relating to the January 2005 fire, and the production capacity expansion to 260,000 bpd.

Sales volume mix of high value diesel fuel and sweet crude products remained relatively consistent year over year (2006 – 53%; 2005 – 54%). Operating issues, plant maintenance activities and the sale of minor amounts of bitumen directly to market have impacted this mix.

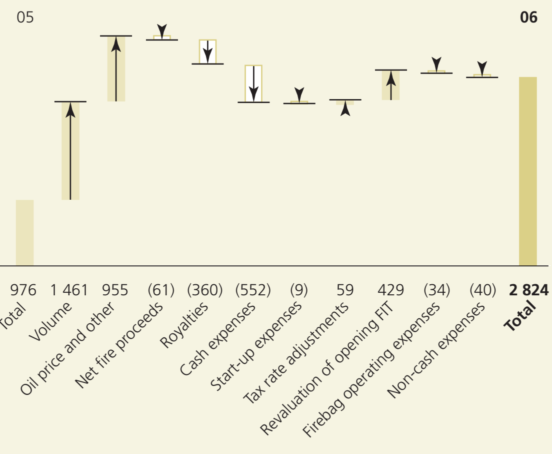
Sales price realizations averaged $68.03 per barrel in 2006 (with no pretax hedging losses) compared with $53.81 per barrel in 2005 (including the impact of pretax hedging losses of $535 million). The average sales price realization was favourably impacted by the absence of hedging losses and stronger WTI benchmark crude oil prices, partially offset by widening differentials for synthetic crude oil, negative impacts on sour crude oil prices due to sales of more sour crude blends at the U.S. Gulf Coast, and by a higher average Cdn$/US$ exchange rate. As crude oil is sold based on U.S. dollar benchmark prices, the increased average Cdn$/US$ exchange rate decreased the Canadian dollar value of crude oil products.

The net impact of the above pricing factors increased net earnings by $955 million in 2006.

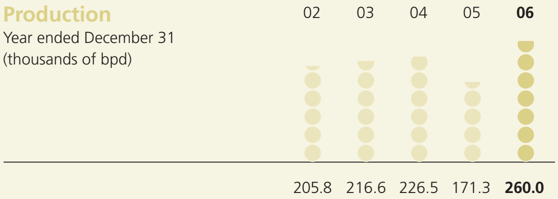
Net Fire Proceeds

In 2006, we recognized $436 million in insurance proceeds (2005 – $572 million), net of the write-off of damaged assets and related expenses. During 2006, we reached final settlement on all our insurance claims relating to the January 2005 fire. This included $92 million (2005 – $115 million) from our property loss policy and $385 million

Bridge Analysis of Net Earnings
($ millions)



Production
Year ended December 31
(thousands of bpd)



(2005 – $594 million) in proceeds from our Business Interruption policies. For further discussion of our insurance activities during the year, see page 26.

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, increased to $2,497 million from $1,629 million in 2005 (2004 – $1,431 million). Expenses were higher year over year due to the following factors:

- Higher total production and sales levels.
- Higher costs associated with unplanned maintenance, including an increase in the purchases of crude oil and products to meet plant and customer demands during maintenance outages.
- Increased transportation costs primarily due to increased volumes shipped out of the Fort McMurray area, and the increased shipments of Oil Sands sour crude blends to the U.S. Gulf Coast market.
- Higher labour costs, including costs associated with maintenance as well as contract labour costs related to managing operations to minimize impacts of the global shortage of heavy vehicle tires.

Overall, increased cash expenses reduced net earnings by $552 million.

Royalties

Oil Sands Alberta Crown royalties increased to $911 million in 2006 compared to $406 million in 2005 (2004 – $407 million). The higher royalty expense reflects the impact of higher sales volumes and commodity prices during 2006. Alberta Oil Sands Crown royalties are subject to change as policies arising from the government's position are finalized and audits of 2006 and prior years are completed. 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 29.

Non-cash Expenses

Non-cash depreciation, depletion and amortization (DD&A) expense increased to $385 million from $330 million in 2005 (2004 – $299 million). The increase was primarily due to the inclusion of newly commissioned upgrading facilities and Firebag Stage 2 operations in our depreciable cost base, during the fourth quarter of 2005. Higher non-cash expenses decreased net earnings by $40 million.

A change in accounting policy for certain non-monetary transactions (see page 41) resulted in certain natural gas costs and offsetting revenues, previously not recorded, being recorded in 2006. The amounts reflected in revenue and expense for 2006 totaled $126 million. There was no impact to net earnings or cash flow from operations.

Tax Adjustments

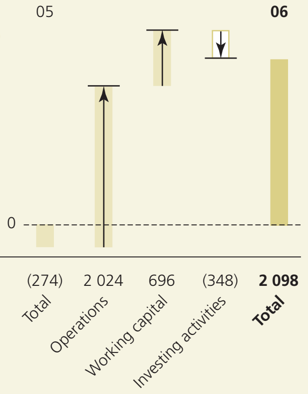
In the second quarter of 2006, reductions to the federal and Alberta provincial income tax rates resulted in a $429 million increase in the net earnings of the Oil Sands segment. These adjustments reduced Oil Sands opening future income tax balances.

Cash Operating Costs per Barrel

Effective January 1, 2006, cash operating costs per barrel, before commissioning and start-up costs, reflect a change in accounting policy to expense overburden costs as incurred (see page 42), as well as the inclusion of research and development costs. The change in accounting policy for overburden resulted in higher cash costs and lower non-cash costs. Therefore, recorded cash operating costs per barrel have increased, but total operating costs were not significantly impacted. Cash operating costs per barrel now reflect total Oil Sands operations including mining and in-situ production costs. In the past, operating costs per barrel for base (mining and upgrading) operations and in-situ operations were disclosed separately. All comparative balances have been retroactively restated for these changes in all 2006 Reports to Shareholders.

Cash operating costs increased to $2,057 million in 2006 from $1,536 million in 2005, as a result of higher maintenance activities, increased labour expenses and insurance related expenses. However, due to these costs being applied to significantly more barrels of production, cash operating costs on a per barrel basis decreased to $21.70 in 2006 from $24.55 in 2005. Refer to page 58 for further details on cash operating costs as a non-GAAP financial measure, including the calculation and reconciliation to GAAP measures.

Bridge Analysis of Net Cash Surplus (Deficiency)
($ millions)



Net Cash Surplus (Deficiency) Analysis

Cash flow from operations was $3,902 million in 2006 compared to $1,878 million in 2005 (2004 – $1,734 million). The increase was primarily due to the same factors that impacted net earnings, excluding the impact of depreciation, depletion and amortization, and the revaluation of future tax balances resulting from the reduction of federal and Alberta provincial income tax rates.

Cash flow used in investing activities increased to $2,230 million in 2006 from $1,882 million in 2005 (2004 – $1,039 million). During 2006, capital spending related primarily to continued progress on the Coker Unit, Firebag in-situ, and Voyageur projects (see "Expansion to 500,000 bpd to 550,000 bpd" below). In addition, during the fourth quarter of 2006 we acquired two separate gross overriding royalty interests relating to a specific land lease, for cash consideration totaling approximately $174 million.

Outlook

Our Oil Sands operations continue to be the focus of our business strategy. In 2007, we anticipate Oil Sands production will average 260,000 to 270,000 bpd from our existing upgrading assets including bitumen sold directly to the market. Our future plans for Oil Sands remain focused on activities and investments anticipated to increase production, identify cost improvements and improve environment, health and safety performance.

For 2007, we have budgeted capital spending of approximately $4.4 billion, of which $900 million is slated for sustaining projects with the remainder earmarked for growth. Approximately $1 billion is allotted to project spending towards the goal of increasing production to 350,000 bpd in 2008, with the remaining $2.5 billion directed toward projects to support the Company's goal of producing more than half a million barrels per day in the 2010 to 2012 time frame.

Expansion to 350,000 bpd

Work to increase production capacity to 350,000 bpd in 2008 continues, and these efforts are proceeding on schedule. During 2007, construction is planned to continue on the Coker Unit and Firebag expansion projects. As a result of this ongoing construction, a 50 day shutdown of Upgrader 2 is planned for 2007 to enable key tie ins for the project. The company intends to take advantage of this planned shutdown to perform necessary maintenance activities. Upgrader 1 is expected to continue to operate at normal capacity during the shutdown. For an update on the progress of these significant capital projects, see page 27.

In addition to our plans to expand our proprietary sources of bitumen supply, incremental bitumen to feed expanded upgrading capacity is also expected to be provided under a processing agreement between Suncor and Petro-Canada, expected to take effect in 2008. Under the agreement, Oil Sands will process a minimum of 27,000 bpd of Petro-Canada bitumen on a fee-for-service basis. Petro-Canada will retain ownership of the bitumen and resulting sour crude oil production of about 22,000 bpd. In addition, we will sell an additional 26,000 bpd of our proprietary sour crude oil production to Petro-Canada. Both the processing and sales components of the agreement are for a minimum 10-year term.

Expansion to 500,000 bpd to 550,000 bpd

In November 2006, the EUB approved our application to construct a third oil sands upgrader, a critical component of our Voyageur strategy, which targets a further expansion of Oil Sands production to 500,000 to 550,000 bpd in 2010 to 2012. The EUB has also conditionally approved our application to develop the North Steepbank mine extension, which is expected to replace bitumen supply from depleted mining leases. Both projects are expected to advance development plans and cost estimates to a level appropriate to seek Board of Directors approval in 2007.

In addition to the planned third upgrader and extension of the Steepbank mine, Suncor's Voyageur strategy also includes the development of Stages 3 to 6 of in-situ bitumen supply from our Firebag leases and infrastructure related to the expansion including an overpass connecting planned facilities on the west side of Highway 63 to existing assets on the east side of the road. As Suncor continues to develop its in-situ projects, we expect to seek Board of Directors approval for Firebag Stage 3 in 2007.

Suncor expects to apply in 2007 for permission to build and extend its mining area to Lease 23 (Voyageur South), west of our existing operations. Pending regulatory and Board of Directors' approval, construction could begin as early as 2009 with mining operations starting in 2011. In addition to pursuing future bitumen supply, Suncor is in the initial stages of investigating future expansion of upgrading capacity. As part of this investigation, we have secured land options northeast of Edmonton, Alberta. There are no firm plans to develop this land, nor are there firm plans about the configuration of any potential future upgrading expansion.

Risk Factors Affecting Performance

There are certain issues we strive to manage that may affect performance including, but not limited to, the following:

- Our ability to finance Oil Sands growth in a volatile commodity pricing environment. Also refer to "Liquidity and Capital Resources" on page 25.
- Our ability to complete future projects both on time and on budget. This could be impacted by competition from other projects (including other oil sands projects) for skilled people, increased demands on the Fort McMurray infrastructure (including housing, roads, services and schools), or higher prices for the products and services required to operate and maintain the operations. 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.
- 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 carefully managed maintenance scheduling.
- 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. These factors are difficult to predict and impossible to control.
- 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 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. (See page 29 for a discussion of anticipated changes).
- 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 2,000 Oil Sands employees. The current collective agreement with the union expires on May 1, 2007.

Additional risks, assumptions and uncertainties are discussed on page 60 under Forward-looking Statements. Also refer to Suncor Overview, Risk Factors Affecting Performance on page 30.

Natural Gas

Suncor's Natural Gas (NG) business primarily produces conventional natural gas in Western Canada. NG's production serves as a price hedge that provides us with a degree of protection from volatile market prices of natural gas purchased for internal consumption in our Oil Sands and downstream operations.

NG's strategy focuses on:

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

NG's long-term goal is to achieve a sustainable return on capital employed (ROCE) (2) of 12% to 15% at mid-cycle prices. To offset company-wide natural gas purchases, NG is targeting production increases of 3% to 5% per year.

HIGHLIGHTS

Summary of Results

Year ended December 31

($ millions unless otherwise noted)	**2006**	2005	2004
Revenue	**578**	679	567
Natural gas production (mmcf/day)	**191**	190	200
Average natural gas sales price ($/mcf)	**7.15**	8.57	6.70
Net earnings	**109**	155	115
Cash flow from operations (1)	**281**	412	319
Total assets	**1 503**	1 307	967
Cash used in investing activities	**443**	344	251
Net cash surplus (deficiency)	**(189)**	63	67
ROCE (%) (2)	**15.3**	30.7	27.1

(1) Non-GAAP measure. See page 58.

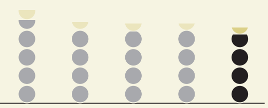
(2) ROCE for Suncor operating segments is calculated in a manner consistent with consolidated ROCE as reconciled in Non-GAAP Financial Measures. See page 58.

2006 Overview

- Natural gas production averaged 191 million cubic feet (mmcf) per day in 2006 compared to 190 mmcf/day in 2005. Company-wide purchases for internal consumption were approximately 170 mmcf/day during 2006. Production in 2006 was below initial targets due to shut-in production as a result of pipeline and processing facility constraints, delays in bringing new production on stream, and an increase in exploratory dry holes compared to 2005.
- During the first quarter of 2006, Suncor sold a 15% interest in the South Rosevear gas plant for proceeds of $12 million. We currently retain a 60.4% interest and continue to operate the plant.

Total Net Proved Reserves

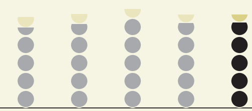
Year ended December 31
(millions of boe) (3)



	02	03	04	05	**06**
Natural gas liquids and crude oil	10	8	8	7	**7**
Natural gas	86	76	74	75	**71**
Total	96	84	82	82	**78**

Production

Year ended December 31
(thousands of boe/d) (3)



	02	03	04	05	**06**
Natural gas liquids and crude oil	3.9	3.7	3.5	3.2	**3.0**
Natural gas	29.8	31.2	33.3	31.6	**31.8**
Total	33.7	34.9	36.8	34.8	**34.8**

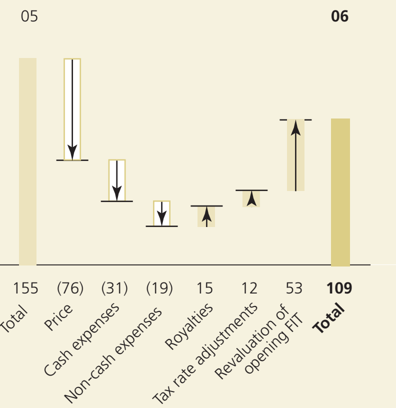
(3) For details on barrels of oil equivalent (boe), see page 18.

Analysis of Net Earnings

NG net earnings were $109 million in 2006, compared to $155 million in 2005 (2004 – $115 million). The decrease in net earnings was due primarily to lower price realizations, higher seismic and dry hole costs, higher operational costs resulting from an inflationary marketplace, and higher depreciation, depletion and amortization (DD&A). The average realized price for natural gas was $7.15 per mcf in 2006, compared to an average of $8.57 per mcf in 2005. These negative factors were partially offset by the reduction in federal and Alberta provincial income tax rates that resulted in a $53 million increase in net earnings during 2006.

NG's total 2006 production was 209 million cubic feet equivalent per day (mmcfe/d) in 2006, unchanged from the prior year.

Bridge Analysis of Net Earnings
($ millions)



Expenses

Royalties on NG production were $127 million ($10.00 per boe) in 2006, compared to $149 million ($11.72 per boe) in 2005 (2004 – $124 million; $9.22 per boe). The decrease was due to lower sales price realizations, reflecting lower benchmark commodity prices.

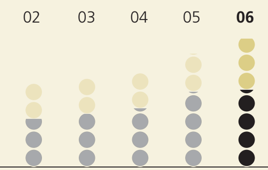
Operating costs were $107 million in 2006 compared to $93 million in 2005 (2004 – $100 million). The increased operating expenses were mainly a result of higher selling, general & administrative costs as well as higher lifting costs caused by the inflationary environment affecting the oil and gas industry in Alberta.

Exploration expenses increased to $82 million in 2006 from $46 million in 2005 (2004 – $38 million). Dry hole costs recognized in the year totaled $52 million, compared to $33 million in 2005. Seismic expenditures increased to $30 million during 2006, compared to $13 million in 2005.

DD&A expense was $152 million in 2006 compared to $130 million in 2005 (2004 – $115 million). The increase was due to higher depletion rates associated with increased finding and development costs.

In total, the above noted items reduced net earnings by $35 million.

Lifting and Administration Costs
Year ended December 31
($/boe)(1)



	02	03	04	05	06
Administration	2.34	2.35	2.39	2.52	**3.37**
Lifting	3.15	3.48	3.84	4.95	**5.08**
Total	5.49	5.83	6.23	7.47	**8.45**

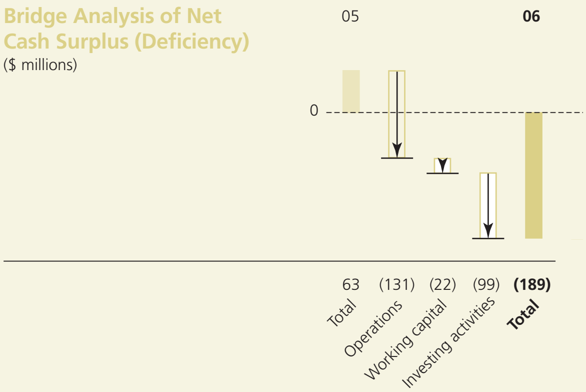
(1) For details on barrels of oil equivalent (boe), see page 18.

Net Cash Surplus (Deficiency) Analysis

NG's net cash deficit was $189 million in 2006 compared with $63 million surplus in 2005 (2004 – $67 million surplus). Cash flow from operations decreased to $281 million compared with $412 million in the prior year (2004 – $319 million), largely due to the same factors impacting earnings.

Cash used in investing activities increased to $443 million compared with $344 million in 2005 (2004 – $251 million) as a result of increased drilling and exploration activities offset by reduced expenditures on pipeline and facility construction.

Bridge Analysis of Net Cash Surplus (Deficiency)
($ millions)



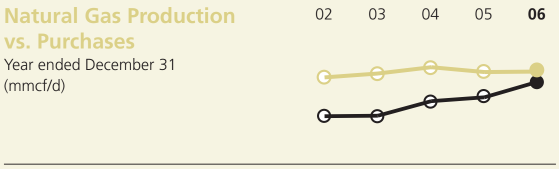
Outlook

NG targets increased production of natural gas, natural gas liquids and crude oil from 209 mmcfe/d in 2006 to 215 to 220 mmcfe/d in 2007 to offset our internal natural gas demands, maintain existing operations and support the company's goal of expanding production by 3% to 5% per year.

NG intends to continue to leverage its expertise and existing assets to bring reserves into production in Western Canada. However, increasing production may require expansion through farm-ins[1], joint ventures or additional property acquisitions, which could expand the size and number of operating areas, or involve new operating areas outside of Western Canada.

To support these goals, we have budgeted $350 million in capital spending primarily for exploration and development in 2007.

Natural Gas Production vs. Purchases
Year ended December 31
(mmcf/d)



	02	03	04	05	**06**
Production	179	187	200	190	**191**
Purchases	99	100	130	138	**170**

Risk Factors Affecting Performance

There are certain issues that we strive to manage that may affect performance of the NG business including, but not limited to, the following:

- Consistently and competitively finding and developing reserves that can be brought on stream economically. Positive or negative reserve revisions arising from technical and economic factors can have a corresponding positive or negative impact on asset valuation and depletion rates.
- The impact of market demand for land and services on capital and operating costs. Market demand and the availability of opportunities also influence the cost of acquisitions and the willingness of competitors to allow farm-ins on prospects.
- The impact of market demand for labour and equipment, which in a heated exploration and development market could add to cost or cause delays to projects for NG and its competitors.
- Risks and uncertainties associated with consulting with stakeholders and obtaining regulatory approval for exploration and development activities in Canada and in the United States. These risks could add to costs 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 with increased costs or reduced production.

Additional risks, assumptions and uncertainties are discussed on page 60 under Forward-looking Statements. Refer to the Suncor Overview, Risk Factors Affecting Performance on page 30.

(1) Acquisition of all or part of the operating rights from the working interest owner. The acquirer assumes all or some of the burden of development in return for an interest in the property. The assignor usually retains an overriding royalty, but may retain any type of interest.

Energy Marketing and Refining – Canada

Energy Marketing and Refining – Canada (EM&R) operates a 70,000 barrel per day (bpd) (approximately 11,100 cubic metres per day) capacity refinery in Sarnia, Ontario, and markets refined products to industrial, wholesale and commercial customers primarily in Ontario and Quebec. Through our Sunoco-branded and joint venture operated service networks, we market products to retail customers in Ontario. The EM&R business also encompasses third party energy marketing and trading activities, as well as providing marketing services for the sale of crude oil and natural gas from our Oil Sands and Natural Gas operations. In 2006, EM&R completed construction of Canada's largest ethanol production plant.

EM&R'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, direct management of growth projects, strategic alliances with key suppliers and customers and continuous improvement of operations.
- Increasing the profitability and efficiency of retail networks.

HIGHLIGHTS

Summary of Results

Year ended December 31 ($ millions unless otherwise noted)	**2006**	2005	2004
Revenue	**5 465**	4 363	3 500
Refined product sales			
(millions of litres)			
Sunoco retail gasoline	**1 678**	1 656	1 665
Total	**5 547**	5 570	5 643
Net earnings breakdown:			
Total earnings excluding energy,			
marketing and trading activities	**54**	30	68
Energy marketing			
and trading activities	**22**	11	12
Tax adjustments	**10**	—	—
Total net earnings	**86**	41	80
Cash flow from operations [1]	**217**	152	188
Total assets	**2 829**	1 955	1 321
Cash used in investing activities	**512**	433	198
Net cash deficiency	**(382)**	(328)	(21)
ROCE (%) [2]	**12.5**	8.1	14.6
ROCE (%) [3]	**7.4**	5.2	13.6

(1) Non-GAAP measure. See page 58.

(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. See page 58.

(3) Includes capitalized costs related to major projects in progress. See page 58.

2006 Overview

- The first phase of our diesel desulphurization and oil sands integration project was completed in July 2006. This phase of the project enables us to produce ultra low sulphur diesel to meet the new regulatory requirements that came into effect June 30, 2006. Phase two of the project, modifications to allow integration of oil sands sour crude feedstocks, is targeted for completion in 2007. Labour shortages and material supply issues have put upward cost pressures on the overall project. The cost estimate for this project has been increased to $960 million, from $800 million.
- A significant planned shutdown at our Sarnia refinery was completed December 22, 2006. Additional capital work that was not included in the original shutdown plan resulted in an extension to completion timelines and higher than anticipated costs.
- On July 1, 2006, Suncor's new ethanol facility began production. The facility, the largest of its kind in Canada, is expected to produce approximately 200 million litres of ethanol annually. The ethanol produced will be used for blending purposes in specific refined products and for sales to third parties.

Analysis of Net Earnings

EM&R results include the impact of Suncor's third party energy marketing and trading activities that are discussed separately on page 53.

EM&R's net earnings increased to $86 million in 2006 from $41 million in 2005 (2004 – $80 million). This increase was primarily due to higher refining margins, offset by lower refinery utilization resulting from the major planned shutdown during the fourth quarter of 2006 and lower retail margins. Net earnings also increased by $5 million as a result of reductions to EM&R's opening future income tax balances (FIT) due to reductions in the federal and Alberta provincial income tax rates during 2006.

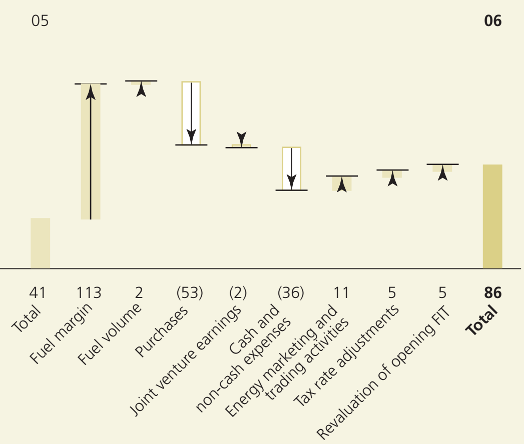
Volumes

Total sales volumes averaged 95,000 bpd (15,100 cubic metres per day) in 2006, comparable to the 96,000 bpd (15,200 cubic metres per day) in 2005. Total gasoline sales volumes in the Sunoco-branded retail network increased to 1,678 million litres in 2006 from 1,656 million litres in 2005. Average Sunoco-branded service station site throughput was unchanged from 2005, at approximately 6 million litres per site in 2006. Site throughput is an important indicator of network efficiency. EM&R's Ontario retail gasoline market share, including all Sunoco and joint venture operated retail sites was 18% in 2006 (2005 – 19%). Approximately 90% of EM&R's refined products were sold to the Ontario market in 2006.

Refinery Utilization

Overall refinery utilization averaged 78% in 2006, compared with 95% in 2005. The reduction in refinery utilization was primarily due to specific operational issues and the extensive planned maintenance activities during 2006.

Bridge Analysis of Net Earnings
($ millions)



Product Purchase Costs

Refined product purchase costs were higher in 2006 as a result of higher purchased volumes of refined products to meet requirements due to operational issues and the maintenance shutdown, along with higher refined product prices. Increased third party purchase costs decreased 2006 net earnings by $53 million.

Cash and Non-cash Operating Expenses

Overall, cash and non-cash operating expenses increased by $36 million after-tax in 2006 compared to 2005. Cash expenses increased by $19 million after-tax in 2006, primarily due to higher administrative costs. Non-cash expenses increased by $17 million after-tax in 2006, due to increased depreciation as a result of a higher depreciable asset base, following the completion of the diesel desulphurization and ethanol projects during the year.

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 GAAP. EM&R 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)	**2006**	2005	2004
Operating revenues			
Sales to EM&R joint ventures:			
Refined products	**294**	327	320
Petrochemicals	**136**	279	272

At December 31, 2006, amounts due from EM&R joint ventures were $20 million, compared to $22 million at December 31, 2005.

Energy Marketing and Trading Activities

Third party energy marketing and energy trading activities consist of both third party crude oil marketing and financial and physical derivatives trading activities. These activities resulted in net earnings after-tax of $22 million in 2006 compared to net earnings of $11 million in 2005 (2004 – $12 million).

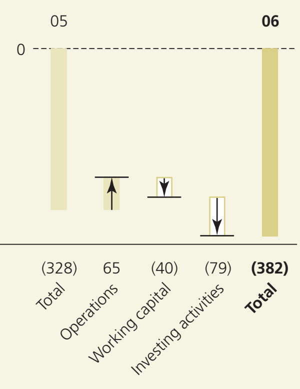
Energy trading activities, by their nature, can result in volatile and large positive or negative fluctuations in earnings. A separate risk management function reviews and monitors practices and policies and provides independent verification and valuation of these activities. See page 33.

Net Cash Deficiency Analysis

EM&R's net cash deficiency was $382 million in 2006 compared to a net cash deficiency of $328 million in 2005 (2004 – net cash deficiency of $21 million). Cash flow from operations was $217 million in 2006 compared to $152 million in 2005 (2004 – $188 million). The increase was due to the same factors impacting net earnings, excluding the revaluation of opening future tax balances resulting from the reduction in federal income tax rates in 2006. Net working capital increased by $87 million in 2006, compared to an increase of $47 million in 2005. The increase in net working capital is a result of a decrease in accounts payable liabilities and an increase to our refined product inventory.

Cash used in investing activities was $512 million in 2006 compared to $433 million in 2005 (2004 – $198 million). Capital expenditures in 2006 were mainly associated with the ongoing diesel desulphurization and oil sands integration project, and the completion of the new ethanol facility. Refinery capital maintenance expenditures also increased during 2006 consistent with the planned maintenance shutdown.

Bridge Analysis of Net Cash Deficiency
($ millions)



Outlook

Completion of the oil sands integration project at the Sarnia refinery, planned for the fourth quarter of 2007, is expected to enable us to process up to 40,000 bpd of oil sands sour crude blends. Tie in of new and modified equipment is expected to require a 65 day shutdown of portions of the facility.

Capital spending, including the completion of the oil sands integration project, is expected to be approximately $300 million in 2007.

Suncor is also investigating a potential expansion of our ethanol plant, near Sarnia. Public consultation began in late 2006. No capital costs or firm plans have yet been defined.

Risk Factors Affecting Performance

There are certain issues we strive to manage that may affect the performance of the EM&R business that include, but are 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.
- Environment Canada is expected to finalize regulations reducing sulphur in off-road diesel fuel and light fuel oil to take effect later in the decade. We believe that if the regulations are finalized as currently proposed, our new facilities for reducing sulphur in on-road diesel fuel should also allow us to meet the requirements for reducing sulphur in off-road diesel and light fuel oil.

Additional risks, assumptions and uncertainties are discussed on page 60 under Forward-looking Statements. Refer to the Suncor Overview, Risk Factors Affecting Performance on page 30.

Refining and Marketing – U.S.A.

Refining and Marketing – U.S.A. (R&M) operates a 90,000 barrel per day (bpd) (approximately 14,300 cubic metre per day) capacity refinery in Commerce City, Colorado, and markets refined products to customers primarily in Colorado, including retail marketing through 43 company owned Phillips 66®-branded retail stations in the Denver area. Assets also include a 100% interest in the 480-kilometre Rocky Mountain pipeline system, a 65% interest in the 140-kilometre Centennial pipeline system and a 100% interest in a products terminal in Grand Junction, Colorado.

R&M's strategy is focused on:

- Enhancing the profitability of refining operations by improving reliability, product yields and operational flexibility to process a variety of feedstocks, including crude oil streams from our Oil Sands operations.
- Creating additional downstream market opportunities in the United States to capture greater long-term value from Oil Sands production.
- Reducing costs through the application of technologies, economies of scale, direct management of growth projects, strategic alliances with key suppliers and customers and continuous improvement of operations.
- Increasing the profitability and efficiency of our retail network.

HIGHLIGHTS

Summary of Results

Year ended December 31

(Cdn$ millions unless otherwise noted)	**2006**	2005	2004
Revenue	**3 128**	2 621	1 495
Refined product sales			
(millions of litres)			
Gasoline	**2 727**	2 517	1 627
Total	**5 256**	5 004	3 504
Net earnings	**168**	142	34
Cash flow from operations (1)	**281**	247	59
Total assets	**1 379**	1 235	518
Cash used in investing activities	**275**	385	171
Net cash deficiency	**(9)**	(121)	(71)
ROCE (%) (2)	**34.2**	49.4	12.2
ROCE (%) (3)	**22.6**	28.9	11.1

(1) Non-GAAP measure. See page 58.

(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. See page 58.

(3) Includes capitalized costs related to major projects in progress. See page 58.

2006 Overview

- R&M's diesel desulphurization project was completed in June 2006. This project enabled production of ultra low sulphur diesel to meet the new regulatory requirements that came into effect June 1, 2006. In addition to improving the refinery's environmental performance, the project modifications enable the refining facility to process up to 15,000 bpd of oil sands sour synthetic crude oil.

Analysis of Net Earnings

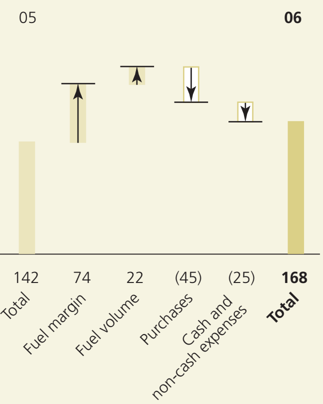
R&M's net earnings were $168 million in 2006 compared to $142 million in 2005 (2004 – $34 million). Earnings increased due to higher refining margins, higher sales volumes due in part to expansion through the acquisition and integration of our second Commerce City refinery in May 2005, and a stronger sales mix of higher value diesel fuel. These positive impacts were partially offset by increased depreciation, depletion and amortization (DD&A) costs after the completion of our diesel desulphurization and oil sands integration project during 2006.

Volumes and Refinery Utilization

Sales volumes increased in 2006 compared to 2005, primarily as a result of the May 2005 acquisition of our second Commerce City refinery (the Colorado Refining Company), which increased throughput capacity of our Commerce City refining facility to 90,000 bpd from 60,000 bpd. This was offset by lower refinery utilization rates resulting from the planned maintenance shutdown in the first quarter of 2006. Refinery utilization was 92% in 2006 compared to 98% in 2005. After the planned maintenance was completed in the first quarter of 2006, utilization rates were comparable with the prior year.

Increased product purchases reduced net earnings by $45 million. The higher volume of purchased refined products was primarily due to purchases of additional finished products to meet customer demands.

Bridge Analysis of Net Earnings
($ millions)



Cash and Non-cash Expenses

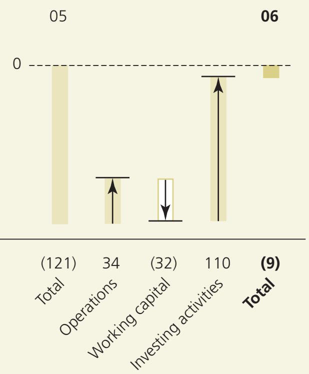
Increases in refinery cash expenses and non-cash expenses were primarily due to incremental costs associated with the acquisition and operation of the additional refinery capacity throughout 2006. As well, depreciation, depletion and amortization costs increased during 2006 following the completion of our diesel desulphurization and oil sands integration project that increased our depreciable cost base.

Net Cash Deficiency Analysis

R&M's net cash deficiency was $9 million in 2006, compared to a deficiency of $121 million in 2005 (2004 – $71 million deficiency). The increase in cash flow from operations to $281 million in 2006 from $247 million in 2005 (2004 – $59 million) was impacted by the same factors that affected net earnings. Net working capital increased $15 million in 2006, compared to a decrease of $17 million in 2005 (2004 – $41 million decrease). The increase in 2006 was primarily due to an increase in our refined product inventory.

Cash used in investing activities was $275 million in 2006, compared to $385 million in 2005 (2004 – $171 million). Investing activities in 2006 were primarily related to costs associated with the diesel desulphurization and oil sands integration project.

Bridge Analysis of Net Cash Deficiency
($ millions)



Outlook

R&M estimates capital spending of approximately $100 million (approximately US$85 million) in 2007, with planned maintenance shutdowns in progress in February and planned in October.

Risk Factors Affecting Performance

There are certain issues we strive to manage that may affect the performance of the R&M business including, but not limited to, the following:

- Continuing fluctuations in demand for refined products, margin and price volatility and market competitiveness, including potential new market entrants.
- 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, assumptions and uncertainties are discussed on page 60 under Forward-looking Statements. Refer to the Suncor Overview, Risk Factors Affecting Performance on page 30.

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		**2006**	2005	2004
Cash flow from operations ($ millions)	A	**4 533**	2 476	2 013
Weighted average number of common shares outstanding (millions of shares)	B	**459**	456	453
Cash flow from operations (per share)	A/B	**9.87**	5.43	4.44

ROCE

For the year ended December 31 ($ millions, except ROCE)		**2006**	2005	2004
Adjusted net earnings				
Net earnings		**2 971**	1 158	1 076
Add: after-tax financing expenses (income)		**26**	(16)	1
	D	**2 997**	1 142	1 077
Capital employed – beginning of year				
Short-term and long-term debt, less cash and cash equivalents		**2 891**	2 159	2 577
Shareholders' equity		**5 996**	4 874	3 858
	E	**8 887**	7 033	6 435
Capital employed – end of year				
Short-term and long-term debt, less cash and cash equivalents		**1 871**	2 891	2 159
Shareholders' equity		**8 952**	5 996	4 874
	F	**10 823**	8 887	7 033
Average capital employed	(E+F)/2=G	**9 855**	7 960	6 734
Average capitalized costs related to major projects in progress	H	**2 476**	2 175	1 030
ROCE (%)	D/(G-H)	**40.6**	19.7	18.9

Oil Sands Operating Costs – Total Operations

(unaudited)		**2006** $ millions	**2006** $/barrel	2005 $ millions	2005 $/barrel	2004 $ millions	2004 $/barrel
Operating, selling and general expenses		**2 149**		1 432		1 179	
Less: natural gas costs and inventory changes		**(312)**		(258)		(181)	
Less: non-monetary transactions		**(126)**		—		—	
Accretion of asset retirement obligations		**28**		24		21	
Taxes other than income taxes		**36**		29		28	
Cash costs		**1 775**	**18.70**	1 227	19.60	1 047	12.60
Natural gas		**276**	**2.90**	307	4.90	197	2.40
Imported bitumen (net of other reported product purchases)		**6**	**0.10**	2	0.05	13	0.15
Total cash operating costs	A	**2 057**	**21.70**	1 536	24.55	1 257	15.15
In-situ (Firebag) start-up costs	B	**21**	**0.20**	7	0.10	24	0.30
Total cash operating costs after start-up costs	A+B	**2 078**	**21.90**	1 543	24.65	1 281	15.45
Depreciation, depletion and amortization		**385**	**4.05**	330	5.30	299	3.60
Total operating costs		**2 463**	**25.95**	1 873	29.95	1 580	19.05
Production (thousands of barrels per day)		**260.0**		171.3		226.5	

Oil Sands Operating Costs – In-situ Bitumen Production Only (excluding upgrading costs)

(unaudited)		**2006** $ millions	**2006** $/barrel	2005 (1) $ millions	2005 (1) $/barrel	2004 (1) $ millions	2004 (1) $/barrel
Operating, selling and general expenses		**209**		155		77	
Less: natural gas costs and inventory changes		**(103)**		(91)		(39)	
Taxes other than income taxes		**4**		—		—	
Cash costs		**110**	**8.95**	64	9.15	38	10.85
Natural gas		**103**	**8.35**	91	13.05	39	11.20
Total cash operating costs	A	**213**	**17.30**	155	22.20	77	22.05
In-situ (Firebag) start-up costs	B	**21**	**1.70**	7	1.00	24	6.85
Total cash operating costs after start-up costs	A+B	**234**	**19.00**	162	23.20	101	28.90
Depreciation, depletion and amortization		**68**	**5.55**	34	4.90	21	6.00
Total operating costs		**302**	**24.55**	196	28.10	122	34.90
Production (thousands of barrels per day)		**33.7**		19.1		12.7	

(1) Firebag start-up costs have not been separately identified in past Annual Reports. We have segregated these costs for comparable information purposes to provide additional detail to the individual components of cash costs.

Forward-looking statements

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

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

The risks, uncertainties and other factors that could influence actual results include but are not limited to changes in the general economic, market and business conditions; fluctuations in supply and demand for Suncor's products; commodity prices and currency exchange rates; Suncor's ability to respond to changing markets and to receive timely regulatory approvals; the successful and timely implementation of capital projects including growth projects (for example the Firebag in-situ development and Voyageur) and regulatory projects; the accuracy of cost estimates, some of which are provided at the conceptual or other preliminary stage of projects and prior to commencement or conception of the detailed engineering needed to reduce the margin of error and increase the level of accuracy; the integrity and reliability of Suncor's capital assets; the cumulative impact of other resource development; future environmental laws; the accuracy of Suncor's reserve, resource and future production estimates and its success at exploration and development drilling and related activities; the maintenance of satisfactory relationships with unions, employee associations and joint venture partners; competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternative sources of energy; uncertainties resulting from potential delays or changes in plans with respect to projects or capital expenditures; actions by governmental authorities including the imposition of taxes or changes to fees and royalties, changes in environmental and other regulations (for example, the Government of Alberta's current review of the Crown Royalty regime, 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 blowouts, freeze-ups, equipment failures and other similar events affecting Suncor or other parties whose operations or assets directly or indirectly affect Suncor.

The foregoing important factors are not exhaustive. Many of these risk factors are discussed in further detail throughout this Management's Discussion and Analysis and in the company's Annual Information Form/Form 40-F on file with Canadian securities commissions at www.sedar.com and the United States Securities and Exchange Commission (SEC) at www.sec.gov. Readers are also referred to the risk factors described in other documents that Suncor files from time to time with securities regulatory authorities. Copies of these documents are available without charge from the company.

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 65 to 103 and all related financial information contained in this Annual Report, including Management's Discussion and Analysis.

We, as Suncor Energy Inc.'s Chief Executive Officer and Chief Financial Officer, have certified Suncor's annual disclosure document filed with the United States Securities and Exchange Commission (Form 40-F) as required by the United States Sarbanes-Oxley Act.

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 65 to 69. 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 all aspects of the company's operations.

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

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 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 28, 2007

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, 2006, 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, 2006.
4. Management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2006, 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 28, 2007

Independent auditors' report

TO THE SHAREHOLDERS OF SUNCOR ENERGY INC.

We have completed integrated audits of the consolidated financial statements and internal control over financial reporting of Suncor Energy Inc. as of December 31, 2006 and December 31, 2004 and an audit of its December 31, 2005 consolidated financial statements. Our opinions, based on our audits, are presented below.

Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Suncor Energy Inc. as at December 31, 2006 and December 31, 2005 and the related consolidated statements of income, cash flows and changes in shareholders' equity for each of the three years in the period ended December 31, 2006. 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, 2006 and December 31, 2004 and for the years then ended in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). We conducted our audit of the Company's financial statements as at December 31, 2005 and for the year ended December 31, 2005 in accordance with Canadian generally accepted auditing standards. 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.

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, 2006 and December 31, 2005 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006 in accordance with Canadian generally accepted accounting principles.

Internal Control Over Financial Reporting

We have also audited management's assessment, included in the accompanying Management's Report on Internal Control over Financial Reporting, that the Company maintained effective internal control over financial reporting as of December 31, 2006, 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. Our responsibility is to express opinions on management's assessment and on the effectiveness of 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, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2006 is fairly stated, in all material respects, based on criteria established in Internal Control – Integrated Framework issued by the COSO. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006 based on criteria established in Internal Control – Integrated Framework issued by the COSO.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta

February 28, 2007

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 financial statements, such as the changes described in note 1 to the consolidated financial statements. Our report to the shareholders dated February 28, 2007 is expressed in accordance with Canadian reporting standards which do not require a reference to such a change in accounting principles in the Auditors' Report when the change is properly accounted for and adequately disclosed in the financial statements.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta

February 28, 2007

Summary of significant accounting policies

Suncor Energy Inc. is a Canadian integrated energy company comprised of four operating segments: Oil Sands, Natural Gas, Energy Marketing and Refining – Canada, and Refining and Marketing – U.S.A.

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 and crude oil in Canada and the United States.

Energy Marketing and Refining – Canada includes the manufacture, transportation and marketing of petroleum, petrochemical and biofuel products, primarily in Ontario and Quebec.

Refining and Marketing – U.S.A. includes the manufacture, transportation and marketing of petroleum and petrochemical products, 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 18.

The consolidated financial statements include the accounts of Suncor Energy Inc. and its subsidiaries and the company's proportionate share of the assets, liabilities, 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. Cash equivalents and short-term investments are stated at cost, which approximates market value.

(c) Revenues

Crude oil sales from upstream operations (Oil Sands and Natural Gas) to downstream operations (Energy Marketing and Refining – Canada and Refining and Marketing – U.S.A.) 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 a portion of its natural gas production 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 and Intangible Assets

Cost

Property, plant and equipment and intangible assets 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.

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.

DOWNSTREAM OPERATIONS (INCLUDING ENERGY MARKETING AND REFINING – CANADA AND REFINING AND MARKETING – U.S.A.) 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. Intangible assets with determinable useful lives are amortized over a maximum period of four years. The amortization of intangible assets is included within depreciation expense in the Consolidated Statements of Earnings.

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.

A significant portion of the company's assets 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 is reviewed regularly, and will be recorded in the first period in which the lives of the assets become determinable.

Impairment

Property, plant and equipment, including capitalized asset retirement costs 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

Deferred charges and other are primarily comprised of deferred maintenance shutdown costs and deferred financing costs.

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 seven years. Normal maintenance and repair costs are charged to expense as incurred.

Financing costs related to the issuance of long-term debt are amortized over the term of the related debt.

(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 ratably 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 LIFO 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.

(h) Derivative Financial Instruments

The company periodically enters into derivative financial instrument commodity contracts such as forwards, futures, swaps and options to hedge against the potential adverse impact of changing market prices due to changes in the underlying commodity indices. The company also periodically enters into derivative financial instrument contracts such as interest rate swaps and foreign currency forwards as part of its risk management strategy to manage exposure to interest and foreign exchange rate fluctuations.

These derivative contracts are initiated within the guidelines of the company's risk management policies, which require stringent authorities for approval and commitment of contracts, designation of the contracts by management as hedges of the related transactions, and monitoring of the effectiveness of such contracts in reducing the related risks. Contract maturities are consistent with the settlement dates of the related hedged transactions.

Derivative contracts accounted for as hedges are not recognized in the Consolidated Balance Sheets. Gains or losses on these contracts, including realized gains and losses on hedging derivative contracts settled prior to maturity, are recognized in earnings and cash flows when the related sales revenues, costs, interest expense and cash flows are recognized. Gains or losses resulting from changes in the fair value of derivative contracts that do not qualify for hedge accounting are recognized in earnings and cash flows when those changes occur.

Canadian Accounting Guideline 13 (AcG 13) "Hedging Relationships" is applicable to the company's hedging relationships. AcG 13 specifies the circumstances in which hedge accounting is appropriate, including the identification, documentation, designation and effectiveness of hedges, as well as the discontinuance of hedge accounting. The Guideline does not specify hedge accounting methods. The company believes that its hedging documentation and tests of effectiveness are prepared in accordance with the provisions of AcG 13.

The company also uses energy derivatives, including physical and financial swaps, forwards and options to earn trading revenues. These energy marketing and trading activities are accounted for at fair value.

Effective January 1, 2007, accounting for financial instruments will change significantly as outlined in Section (l) "Recently Issued Canadian Accounting Standards."

(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. 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.

The company's Refining and Marketing – U.S.A. operations, and 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 cumulative foreign currency translation in the Consolidated Statements of Changes in Shareholders' Equity.

(j) Stock-based Compensation Plans

Under the company's common share option programs (see note 11), common share options are granted to executives, employees and non-employee directors.

Compensation expense is recorded in the Consolidated Statements of Earnings 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 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.

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

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 over the estimated vesting periods of the respective award.

See also Section (l) "Recently Issued Canadian Accounting Standards."

(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.

(l) Recently Issued Canadian Accounting Standards

Financial Instruments/Other Comprehensive Income/Hedges

In 2005, the Canadian Institute of Chartered Accountants (CICA) approved Handbook section 3855 "Financial Instruments – Recognition and Measurement," section 1530 "Comprehensive Income" and section 3865 "Hedges." Effective January 1, 2007, these standards require the presentation of financial instruments at fair value on the balance sheet. These standards must be applied prospectively with an initial recognition adjustment to retained earnings and accumulated other comprehensive income.

For specific transactions identified as hedges, changes in fair value are recognized in net earnings or other comprehensive income based on the type and effectiveness of the individual instruments. Upon adoption the company's presentation will be more aligned with the current U.S. GAAP reporting as outlined in note 18 to the consolidated financial statements.

Other comprehensive income will represent the foreign currency translation of self-sustaining subsidiaries, the fair value gains/losses of specific financial investments (available for sale) and the effective portion of gains/losses of cash flow hedges. Presentation of other comprehensive income will require a change in the presentation of the Consolidated Statements of Earnings, and result in a new Statement of Comprehensive Income.

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

- Financial Assets – $26 million
- Financial Liabilities – $13 million
- Retained Earnings – $5 million
- Cumulative Foreign Currency Translation – $71 million
- Accumulated Other Comprehensive Loss – $63 million

No restatement of comparative balances is permitted.

The CICA has approved additional financial instrument and capital disclosure requirements. These new requirements will become effective on January 1, 2008.

Accounting Changes

In 2006, the CICA approved revisions to Handbook section 1506 "Accounting Changes." Effective January 1, 2007, accounting policy changes are permitted only in the event a change is made within a primary source of GAAP, or where a change is warranted to provide more relevant and reliable information. All accounting policy changes are to be applied retrospectively, unless impracticable. Any prior period errors identified also require retrospective application. The revised standards will not impact net earnings or financial position.

Stock-based Compensation

On July 6, 2006, the Emerging Issues Committee (EIC) of the CICA approved an abstract (EIC 162) addressing the recognition of stock-based compensation expenses for employees eligible to retire prior to the vesting date of any award(s) issued. The abstract requires that the compensation expense be recognized over the term until the employee is eligible to retire, when earlier than the award vesting date. If the employee is eligible to retire at the time of grant, the award is to be expensed immediately. The abstract was applied retrospectively, effective December 31, 2006. No material adjustment was required in applying this standard.

Consolidated statements of earnings

For the years ended December 31 ($ millions)	**2006**	2005	2004
Revenues			
Operating revenues (notes 6, 16 and 17)	**13 798**	9 728	8 270
Energy marketing and trading activities (note 6c)	**1 582**	827	432
Net insurance proceeds	**436**	572	—
Interest	**13**	2	3
	15 829	11 129	8 705
Expenses			
Purchases of crude oil and products	**4 723**	4 184	2 867
Operating, selling and general	**2 998**	2 417	1 991
Energy marketing and trading activities (note 6c)	**1 541**	789	413
Transportation and other costs	**212**	152	132
Depreciation, depletion and amortization (note 1)	**695**	568	514
Accretion of asset retirement obligations	**34**	30	26
Exploration (note 17)	**104**	56	55
Royalties (note 4)	**1 038**	555	531
Taxes other than income taxes (note 17)	**595**	529	540
Gain on disposal of assets	**(1)**	(13)	(16)
Project start-up costs	**45**	25	26
Financing expenses (income) (note 14)	**39**	(15)	24
	12 023	9 277	7 103
Earnings Before Income Taxes	**3 806**	1 852	1 602
Provision for income taxes (note 9)			
Current	**20**	39	69
Future	**815**	655	457
	835	694	526
Net Earnings	**2 971**	1 158	1 076
Per Common Share (dollars) (note 12)			
Net earnings attributable to common shareholders			
Basic	**6.47**	2.54	2.38
Diluted	**6.32**	2.48	2.33
Cash dividends	**0.30**	0.24	0.23

See accompanying Summary of Significant Accounting Policies and Notes.

Consolidated balance sheets

As at December 31 ($ millions)	**2006**	2005
Assets		
Current assets		
Cash and cash equivalents	**521**	165
Accounts receivable (notes 10 and 17)	**1 050**	1 139
Inventories (note 15)	**589**	523
Income taxes receivable	**33**	6
Future income taxes (note 9)	**109**	83
Total current assets	**2 302**	1 916
Property, plant and equipment, net (note 2)	**16 189**	12 966
Deferred charges and other (note 3)	**290**	267
Total assets	**18 781**	15 149
Liabilities and Shareholders' Equity		
Current liabilities		
Short-term debt	**7**	49
Accounts payable and accrued liabilities (notes 7 and 8)	**2 111**	1 830
Taxes other than income taxes	**40**	56
Total current liabilities	**2 158**	1 935
Long-term debt (note 5)	**2 385**	3 007
Accrued liabilities and other (notes 7 and 8)	**1 214**	1 005
Future income taxes (note 9)	**4 072**	3 206
Total liabilities	**9 829**	9 153
Commitments and contingencies (note 10)		
Shareholders' equity		
Share capital (note 11)	**794**	732
Contributed surplus (note 11)	**100**	50
Cumulative foreign currency translation	**(71)**	(81)
Retained earnings	**8 129**	5 295
Total shareholders' equity	**8 952**	5 996
Total liabilities and shareholders' equity	**18 781**	15 149

See accompanying Summary of Significant Accounting Policies and Notes.

Approved on behalf of the Board of Directors:

Richard L. George
Director

John T. Ferguson
Director

February 28, 2007

Consolidated statements of cash flows

For the years ended December 31 ($ millions)	**2006**	2005	2004
Operating Activities			
Cash flow from operations [(a)]	**4 533**	2 476	2 013
Decrease (increase) in operating working capital			
Accounts receivable	**53**	(477)	(121)
Inventories	**(66)**	(63)	(51)
Accounts payable and accrued liabilities	**87**	435	201
Taxes payable	**(43)**	(23)	16
Cash flow from operating activities	**4 564**	2 348	2 058
Cash Used in Investing Activities [(a)]	**(3 489)**	(3 113)	(1 689)
Net Cash Surplus (Deficiency) Before Financing Activities	**1 075**	(765)	369
Financing Activities			
Increase (decrease) in short-term debt	**(42)**	19	(1)
Net increase (decrease) in other long-term debt	**(622)**	808	(635)
Issuance of common shares under stock option plans	**45**	69	41
Dividends paid on common shares	**(127)**	(102)	(97)
Deferred revenue	**27**	50	26
Cash flow provided by (used in) financing activities	**(719)**	844	(666)
Increase (Decrease) in Cash and Cash Equivalents	**356**	79	(297)
Effect of Foreign Exchange on Cash and Cash Equivalents	**—**	(2)	(3)
Cash and Cash Equivalents at Beginning of Year	**165**	88	388
Cash and Cash Equivalents at End of Year	**521**	165	88

(a) See Schedules of Segmented Data on pages 76 and 77.

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	Cumulative Foreign Currency Translation	Retained Earnings
At December 31, 2003, as previously reported	604	7	(26)	3 308
Retroactive adjustment for change in accounting policy, net of tax (note 1)	—	—	—	(35)
At December 31, 2003, as restated	604	7	(26)	3 273
Net earnings	—	—	—	1 076
Dividends paid on common shares	—	—	—	(97)
Issued for cash under stock option plans	41	—	—	—
Issued under dividend reinvestment plan	6	—	—	(6)
Stock-based compensation expense	—	25	—	—
Foreign currency translation adjustment	—	—	(29)	—
At December 31, 2004, as restated	651	32	(55)	4 246
Net earnings	—	—	—	1 158
Dividends paid on common shares	—	—	—	(102)
Issued for cash under stock option plans	74	(5)	—	—
Issued under dividend reinvestment plan	7	—	—	(7)
Stock-based compensation expense	—	23	—	—
Foreign currency translation adjustment	—	—	(26)	—
At December 31, 2005, as restated	**732**	**50**	**(81)**	**5 295**
Net earnings	**—**	**—**	**—**	**2 971**
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**	**—**	**—**
Foreign currency translation adjustment	**—**	**—**	**10**	**—**
Income tax benefit of stock option deductions in the U.S.	**—**	**4**	**—**	**—**
At December 31, 2006	**794**	**100**	**(71)**	**8 129**

See accompanying Summary of Significant Accounting Policies and Notes.

Schedules of segmented data [a]

For the years ended December 31 ($ millions)	Oil Sands 2006	Oil Sands 2005	Oil Sands 2004	Natural Gas 2006	Natural Gas 2005	Natural Gas 2004	Energy Marketing and Refining – Canada 2006	Energy Marketing and Refining – Canada 2005	Energy Marketing and Refining – Canada 2004
EARNINGS									
Revenues [b]									
Operating revenues	**6 259**	2 938	3 215	**554**	632	499	**3 858**	3 536	3 060
Energy marketing and trading activities	**—**	—	—	**—**	—	—	**1 607**	827	440
Net insurance proceeds	**436**	572	—	**—**	—	—	**—**	—	—
Intersegment revenues [c]	**712**	455	425	**23**	47	68	**—**	—	—
Interest	**—**	—	—	**1**	—	—	**—**	—	—
	7 407	3 965	3 640	**578**	679	567	**5 465**	4 363	3 500
Expenses									
Purchases of crude oil and products	**89**	32	75	**—**	—	—	**2 876**	2 585	2 115
Operating, selling and general	**2 149**	1 432	1 179	**107**	93	100	**432**	484	418
Energy marketing and trading activities	**—**	—	—	**—**	—	—	**1 572**	810	421
Transportation and other costs	**162**	104	88	**25**	22	21	**6**	6	3
Depreciation, depletion and amortization	**385**	330	299	**152**	130	115	**94**	73	69
Accretion of asset retirement obligations	**28**	24	21	**5**	5	4	**1**	1	1
Exploration	**22**	10	17	**82**	46	38	**—**	—	—
Royalties (note 4)	**911**	406	407	**127**	149	124	**—**	—	—
Taxes other than income taxes	**75**	51	72	**3**	3	2	**359**	338	352
(Gain) loss on disposal of assets	**—**	—	4	**(4)**	(12)	(19)	**3**	(1)	(2)
Project start-up costs	**38**	25	26	**—**	—	—	**2**	—	—
Financing expenses (income)	**—**	—	—	**—**	—	—	**—**	—	—
	3 859	2 414	2 188	**497**	436	385	**5 345**	4 296	3 377
Earnings (loss) before income taxes	**3 548**	1 551	1 452	**81**	243	182	**120**	67	123
Income taxes	**(724)**	(575)	(482)	**28**	(88)	(67)	**(34)**	(26)	(43)
Net earnings (loss)	**2 824**	976	970	**109**	155	115	**86**	41	80
As at December 31									
TOTAL ASSETS	**13 692**	11 648	9 000	**1 503**	1 307	967	**2 829**	1 955	1 321

(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 2006, 2005 or 2004 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)	Refining and Marketing U.S.A. 2006	2005	2004	Corporate and Eliminations 2006	2005	2004	Total 2006	2005	2004
EARNINGS									
Revenues [b]									
Operating revenues	**3 123**	2 619	1 494	**4**	3	2	**13 798**	9 728	8 270
Energy marketing and trading activities	**—**	—	—	**(25)**	—	(8)	**1 582**	827	432
Net insurance proceeds	**—**	—	—	**—**	—	—	**436**	572	—
Intersegment revenues [c]	**—**	—	—	**(735)**	(502)	(493)	**—**	—	—
Interest	**5**	2	1	**7**	—	2	**13**	2	3
	3 128	2 621	1 495	**(749)**	(499)	(497)	**15 829**	11 129	8 705
Expenses									
Purchases of crude oil and products	**2 477**	2 048	1 171	**(719)**	(481)	(494)	**4 723**	4 184	2 867
Operating, selling and general	**170**	167	124	**140**	241	170	**2 998**	2 417	1 991
Energy marketing and trading activities	**—**	—	—	**(31)**	(21)	(8)	**1 541**	789	413
Transportation and other costs	**19**	20	20	**—**	—	—	**212**	152	132
Depreciation, depletion and amortization	**38**	23	22	**26**	12	9	**695**	568	514
Accretion of asset retirement obligations	**—**	—	—	**—**	—	—	**34**	30	26
Exploration	**—**	—	—	**—**	—	—	**104**	56	55
Royalties (note 4)	**—**	—	—	**—**	—	—	**1 038**	555	531
Taxes other than income taxes	**157**	137	114	**1**	—	—	**595**	529	540
(Gain) loss on disposal of assets	**—**	—	1	**—**	—	—	**(1)**	(13)	(16)
Project start-up costs	**5**	—	—	**—**	—	—	**45**	25	26
Financing expenses (income)	**—**	—	—	**39**	(15)	24	**39**	(15)	24
	2 866	2 395	1 452	**(544)**	(264)	(299)	**12 023**	9 277	7 103
Earnings (loss) before income taxes	**262**	226	43	**(205)**	(235)	(198)	**3 806**	1 852	1 602
Income taxes	**(94)**	(84)	(9)	**(11)**	79	75	**(835)**	(694)	(526)
Net earnings (loss)	**168**	142	34	**(216)**	(156)	(123)	**2 971**	1 158	1 076
As at December 31									
TOTAL ASSETS	**1 379**	1 235	518	**(622)**	(996)	(32)	**18 781**	15 149	11 774

Schedules of segmented data [a] (continued)

For the years ended December 31 ($ millions)	Oil Sands **2006**	Oil Sands 2005	Oil Sands 2004	Natural Gas **2006**	Natural Gas 2005	Natural Gas 2004	Energy Marketing and Refining – Canada **2006**	Energy Marketing and Refining – Canada 2005	Energy Marketing and Refining – Canada 2004
CASH FLOW BEFORE FINANCING ACTIVITIES									
Cash from (used in) operating activities:									
Cash flow from (used in) operations									
Net earnings (loss)	**2 824**	976	970	**109**	155	115	**86**	41	80
Exploration expenses	**—**	—	—	**52**	46	38	**—**	—	—
Non-cash items included in earnings									
Depreciation, depletion and amortization	**385**	330	299	**152**	130	115	**94**	73	69
Income taxes	**724**	575	482	**(28)**	88	67	**34**	26	43
(Gain) loss on disposal of assets	**—**	—	4	**(4)**	(12)	(19)	**3**	(1)	(2)
Stock-based compensation expense	**—**	—	—	**—**	—	—	**—**	—	—
Other	**(10)**	11	(29)	**—**	5	4	**—**	13	(3)
Increase (decrease) in deferred credits and other	**(21)**	(14)	8	**—**	—	(1)	**—**	—	1
Total cash flow from (used in) operations	**3 902**	1 878	1 734	**281**	412	319	**217**	152	188
Decrease (increase) in operating working capital	**426**	(270)	24	**(27)**	(5)	(1)	**(87)**	(47)	(11)
Total cash from (used in) operating activities	**4 328**	1 608	1 758	**254**	407	318	**130**	105	177
Cash from (used in) investing activities:									
Capital and exploration expenditures	**(2 463)**	(1 948)	(1 119)	**(458)**	(363)	(279)	**(487)**	(442)	(228)
Acquisition of Denver refineries and related assets	**—**	—	—	**—**	—	—	**—**	—	—
Property loss insurance proceeds	**36**	44	—	**—**	—	—	**—**	—	—
Deferred maintenance shutdown expenditures	**—**	(65)	(4)	**—**	(2)	(1)	**(29)**	—	(20)
Deferred outlays and other investments	**(2)**	(1)	(9)	**—**	—	—	**1**	3	(14)
Proceeds from disposals	**2**	41	45	**15**	21	29	**4**	3	3
Decrease (increase) in investing working capital	**197**	47	48	**—**	—	—	**(1)**	3	61
Total cash (used in) investing activities	**(2 230)**	(1 882)	(1 039)	**(443)**	(344)	(251)	**(512)**	(433)	(198)
Net cash surplus (deficiency) before financing activities	**2 098**	(274)	719	**(189)**	63	67	**(382)**	(328)	(21)

(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)	Refining and Marketing U.S.A. 2006	2005	2004	Corporate and Eliminations 2006	2005	2004	Total 2006	2005	2004
CASH FLOW BEFORE FINANCING ACTIVITIES									
Cash from (used in) operating activities:									
Cash flow from (used in) operations									
Net earnings (loss)	**168**	142	34	**(216)**	(156)	(123)	**2 971**	1 158	1 076
Exploration expenses	**—**	—	—	**—**	—	—	**52**	46	38
Non-cash items included in earnings									
Depreciation, depletion and amortization	**38**	23	22	**26**	12	9	**695**	568	514
Income taxes	**94**	84	9	**(9)**	(118)	(144)	**815**	655	457
(Gain) loss on disposal of assets	**—**	—	1	**—**	—	—	**(1)**	(13)	(16)
Stock-based compensation expense	**—**	—	—	**53**	23	25	**53**	23	25
Other	**(16)**	(2)	(8)	**12**	(60)	(71)	**(14)**	(33)	(107)
Increase (decrease) in deferred credits and other	**(3)**	—	1	**(14)**	86	17	**(38)**	72	26
Total cash flow from (used in) operations	**281**	247	59	**(148)**	(213)	(287)	**4 533**	2 476	2 013
Decrease (increase) in operating working capital	**(15)**	17	41	**(266)**	177	(8)	**31**	(128)	45
Total cash from (used in) operating activities	**266**	264	100	**(414)**	(36)	(295)	**4 564**	2 348	2 058
Cash from (used in) investing activities:									
Capital and exploration expenditures	**(178)**	(337)	(190)	**(27)**	(63)	(31)	**(3 613)**	(3 153)	(1 847)
Acquisition of Denver refineries and related assets	**—**	(62)	—	**—**	—	—	**—**	(62)	—
Property loss insurance proceeds	**—**	—	—	**—**	—	—	**36**	44	—
Deferred maintenance shutdown expenditures	**(51)**	(10)	(7)	**—**	—	—	**(80)**	(77)	(32)
Deferred outlays and other investments	**6**	1	(1)	**(2)**	(6)	1	**3**	(3)	(23)
Proceeds from disposals	**—**	—	—	**—**	—	—	**21**	65	77
Decrease (increase) in investing working capital	**(52)**	23	27	**—**	—	—	**144**	73	136
Total cash (used in) investing activities	**(275)**	(385)	(171)	**(29)**	(69)	(30)	**(3 489)**	(3 113)	(1 689)
Net cash surplus (deficiency) before financing activities	**(9)**	(121)	(71)	**(443)**	(105)	(325)	**1 075**	(765)	369

Notes to the consolidated financial statements

1. CHANGES IN ACCOUNTING POLICIES

(a) Overburden Removal Costs

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

Change in Consolidated Balance Sheets

($ millions, (decrease))	**2006**	2005
Deferred charges and other	**(230)**	(202)
Total assets	**(230)**	(202)
Future income tax liabilities	**(77)**	(68)
Retained earnings	**(153)**	(134)
Total liabilities and shareholders' equity	**(230)**	(202)

Change in Consolidated Statements of Earnings

($ millions, increase/(decrease))	**2006**	2005	2004
Operating, selling and general	**337**	287	222
Depreciation, depletion and amortization	**(309)**	(152)	(206)
Future income taxes	**(9)**	(48)	(4)
Net earnings	**(19)**	(87)	(12)
Per common share – basic (dollars)	**(0.04)**	(0.19)	(0.03)
Per common share – diluted (dollars)	**(0.04)**	(0.19)	(0.03)

(b) Non-monetary Transactions

On January 1, 2006, the company prospectively adopted CICA Handbook section 3831 "Non-monetary Transactions." The standard requires all non-monetary transactions to be measured at fair value (if determinable) unless future cash flows are not expected to change significantly as a result of a transaction or the transaction is an exchange of a product held for sale in the ordinary course of business. The company was required to record the effects of an existing contract at Oil Sands that exchanges off-gas produced as a by-product of the upgrading operations for natural gas. An equal amount of revenues for the sale of the off-gas and purchases of crude oil and products for the purchase of the natural gas are recorded. The amount of the gross up of revenues and purchases of crude oil and products for the year ended December 31, 2006, was $126 million.

2. PROPERTY, PLANT AND EQUIPMENT

($ millions)	**2006** Cost	**2006** Accumulated Provision	2005 Cost	2005 Accumulated Provision
Oil Sands				
Plant	**7 514**	**1 608**	6 042	1 388
Mine and mobile equipment	**1 191**	**320**	939	280
In-situ properties	**1 946**	**147**	1 608	79
Pipeline	**149**	**34**	139	30
Capital leases	**38**	**4**	30	6
Major projects in progress	**2 887**	**—**	2 484	—
Asset retirement cost	**663**	**94**	408	81
	14 388	**2 207**	11 650	1 864
Natural Gas				
Proved properties	**1 931**	**867**	1 632	769
Unproved properties	**186**	**21**	172	23
Other support facilities and equipment	**90**	**23**	53	13
Asset retirement cost	**44**	**7**	14	6
	2 251	**918**	1 871	811
Energy Marketing and Refining – Canada				
Refinery	**1 441**	**529**	899	481
Marketing	**626**	**250**	597	244
Major projects in progress	**386**	**—**	464	—
Asset retirement cost	**13**	**7**	11	7
	2 466	**786**	1 971	732
Refining and Marketing – U.S.A.				
Refinery and intangible assets	**826**	**55**	244	24
Marketing	**43**	**5**	36	3
Pipeline	**35**	**3**	26	2
Major projects in progress	**—**	**—**	453	—
	904	**63**	759	29
Corporate	**208**	**54**	180	29
	20 217	**4 028**	16 431	3 465
Net property, plant and equipment		**16 189**		12 966

3. DEFERRED CHARGES AND OTHER

($ millions)	**2006**	2005
Deferred maintenance shutdown costs	**143**	160
Deferred government tax credits	**74**	20
Deferred financing costs	**22**	23
Other	**51**	64
Total deferred charges and other	**290**	267

4. ROYALTIES

Alberta Crown royalties in effect for each Oil Sands project require payments to the Government of Alberta based on annual gross revenues less related transportation costs (R) less allowable costs (C), including the deduction of certain capital expenditures (the 25% R-C royalty), subject to a minimum payment of 1% of R. Firebag is treated by the Government of Alberta as a separate project from the rest of the Oil Sands operations for royalty purposes. During 2004 to 2006, Firebag was subject to the minimum payment of 1% of R. However, for the rest of Oil Sands, the 2004 calendar year was a transitional year, as the remaining amount of prior years' allowable costs carried forward of approximately $600 million were claimed before the 25% R-C royalty applied to 2004 results.

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

During the fourth quarter of 2006, Suncor exercised its option to move our Oil Sands operations to the bitumen based royalty regime effective January 1, 2009.

Royalty expense for the company's Oil Sands operations for the year ended December 31, 2006, was $911 million (2005 – $406 million; 2004 – $407 million).

5. LONG-TERM DEBT

A. Fixed-term Debt, Redeemable at the Option of the Company

($ millions)	**2006**	2005
5.95% Notes, denominated in U.S. dollars, due in 2034 (US$500)	**583**	583
7.15% Notes, denominated in U.S. dollars, due in 2032 (US$500)	**583**	583
6.70% Series 2 Medium-term Notes, due in 2011 (i)	**500**	500
6.80% Medium-term Notes, due in 2007 (i)	**250**	250
6.10% Medium-term Notes, due in 2007 (i)	**150**	150
	2 066	2 066
Revolving-term debt, with interest at variable rates (see B. Credit Facilities)		
Commercial Paper (interest at December 31, 2006 – 4.3%; 2005 – 3.2%) (ii)	**280**	890
Total unsecured long-term debt	**2 346**	2 956
Secured long-term debt with interest rates averaging 6.6% (2005 – 5.2%)	**1**	1
Capital leases (iii), (iv)	**38**	30
Variable interest entity long-term debt – See note 10	**—**	20
Total long-term debt	**2 385**	3 007

(i) The company entered into various interest rate swap transactions in 2004. 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 2006	Effective Interest Rate 2005
Swap of 6.70% Medium-term Notes to floating rates	200	2011	5.2%	4.0%
Swap of 6.80% Medium-term Notes to floating rates	250	2007	6.0%	4.6%
Swap of 6.10% Medium-term Notes to floating rates	150	2007	5.3%	4.0%

(ii) The company is authorized to issue commercial paper to a maximum of $1,200 million having a term not to exceed 364 days. Commercial paper is supported by unutilized credit and term loan facilities (see B. Credit Facilities).

(iii) Obligations under capital leases are as follows:

($ millions)	**2006**	2005
Equipment leases with interest rates between prime plus 0.5% and 12.4% and maturity dates ranging from 2008 to 2035	**38**	30

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

($ millions)	Capital Leases	Other Long-term Debt
2007	3	681 [(a)]
2008	3	—
2009	3	—
2010	4	—
2011	4	500
Later years	72	1 166
Total minimum payments	89	2 347
Less amount representing imputed interest	51	
Present value of obligation under capital leases	38	

Long-term Debt (per cent)	**2006**	2005
Variable rate	**37**	50
Fixed rate	**63**	50

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

B. Credit Facilities

During 2006, a $1.5 billion credit facility agreement was renegotiated and extended by two years, to have a five-year term maturing in June 2011. The credit limit of this facility was also increased by $500 million to $2 billion. In addition, a $200 million credit facility agreement was renegotiated and increased by $100 million to $300 million. As well, a $600 million credit facility agreement matured during the second quarter and was not renewed. At December 31, 2006, the company had available credit facilities of $2,330 million, of which $1,813 million was undrawn, as follows:

($ millions)	
Facility that is fully revolving for 364 days, has a term period of one year and expires in 2008	300
Facility that is fully revolving for a period of five years and expires in 2011	2 000
Facilities that can be terminated at any time at the option of the lenders	30
Total available credit facilities	2 330
Credit facilities supporting outstanding commercial paper and standby letters of credit	517
Total undrawn credit facilities	1 813

At December 31, 2006, the company had issued $237 million (2005 – $185 million) in letters of credit to various third parties and had outstanding commercial paper of $280 million (2005 – $890 million).

6. FINANCIAL INSTRUMENTS

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 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 manage the exposure to losses that could result if commodity prices or foreign currency exchange 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 can protect against adverse changes in commodity prices, interest rates, or foreign currency exchange rates.

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

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

See below for more technical details and amounts.

(a) Balance Sheet Financial Instruments

The company's financial instruments recognized in the Consolidated Balance Sheets consist of cash and cash equivalents, accounts receivable, derivative contracts not accounted for as hedges, substantially all current liabilities (except for the current portions of asset retirement and pension obligations), and long-term debt.

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; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction.

The following table summarizes estimated fair value information about the company's financial instruments recognized in the Consolidated Balance Sheets at December 31:

	2006		2005	
($ millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	**521**	**521**	165	165
Accounts receivable	**1 050**	**1 050**	1 139	1 139
Current liabilities	**1 987**	**1 987**	1 826	1 826
Long-term debt				
Fixed-term	**2 066**	**2 208**	2 066	2 299
Revolving-term	**280**	**280**	890	890
Other	**1**	**1**	21	21
Capital leases	**38**	**38**	30	30

The fair values of the company's fixed and revolving-term long-term debt, capital leases, and other long-term debt were determined through comparisons to similar debt instruments.

(b) Unrecognized Derivative Financial Instruments

The company is also a party to certain derivative financial instruments that are not recognized in the Consolidated Balance Sheets, as follows:

Revenue, Cost and Margin Hedges

Suncor operates in a global industry where the market price of its petroleum and natural gas products is determined based on floating benchmark indices denominated in U.S. dollars. The company periodically enters into derivative financial instrument contracts such as forwards, futures, swaps, options and costless collars to hedge against the potential adverse impact of changing market prices due to changes in the underlying indices. Specifically, the company manages crude sales price variability by entering into West Texas Intermediate (WTI) derivative transactions. As at December 31, 2006, the company had hedged a portion of its forecasted Canadian and U.S. dollar denominated cash flows subject to U.S. dollar WTI commodity price risk for 2007 and 2008. As at December 31, 2006, the company had outstanding costless collar agreements covering 60,000 barrels per day (bpd) in 2007 and 10,000 bpd in 2008. Prices for these barrels are fixed within a range of US$51.64 to US$93.26 per barrel in 2007 and US$59.85 to US$101.06 per barrel in 2008. The company has not hedged any portion of the foreign exchange component of these forecasted cash flows.

At December 31, 2006, the company had hedged a portion of its forecasted cash flows related to natural gas production and refinery operations, as well as a portion of its Euro dollar exposure created by the anticipated purchase of equipment payable in Euros in 2007.

The financial instrument 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. For accounting purposes, amounts received or paid on settlement are recorded as part of the related hedged sales or purchase transactions.

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, 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**
As at December 31, 2005				
Costless collars	7 000	50.00 – 92.57	149 – 276	2006
Costless collars	7 000	50.00 – 92.57	149 – 276	2007
As at December 31, 2004				
Crude oil swaps	36 000	23	364	2005

Natural Gas	Quantity (GJ/day)	Average Price (Cdn$/GJ)	Revenue Hedged (Cdn$ millions)	Hedge Period[c]
As at December 31, 2006				
Swaps	**4 000**	**6.11**	**9**	**2007**
As at December 31, 2005				
Swaps	4 000	6.58	10	2006
Costless collars	25 000	10.76 – 16.13	24 – 36	2006[d]
Costless collars	10 000	8.75 – 13.38	19 – 29	2006[e]
Swaps	4 000	6.11	9	2007
As at December 31, 2004				
Natural Gas Swaps	4 000	7	10	2005
Natural Gas Swaps	4 000	7	10	2006
Natural Gas Swaps	4 000	6	9	2007
Costless collars	10 000	8 – 9	7 – 8	2005[f]

Margin Hedges	Quantity (bpd)	Average Margin US$/bbl	Margin Hedged (Cdn$ millions)[b]	Hedge Period[c]
Refined product sale and crude purchase swaps				
As at December 31, 2006	**—**	**—**	**—**	**—**
As at December 31, 2005	5 100	11.69	10	2006[g]
As at December 31, 2004	6 300	7	15	2005[h]

Foreign Currency Hedges	Notional (Euro millions)	Average Forward Rate	Dollars Hedged (Cdn$ millions)	Hedge Period
As at December 31, 2006				
Euro/Cdn forward	**20.6**	**1.41**	**29.0**	**2007**[i]
As at December 31, 2005				
Euro/Cdn forward	9.9	1.39	13.8	2006[j]
Euro/Cdn forward	20.6	1.41	29.0	2007[i]

(a) Average price for crude oil swaps and costless collars is US$ WTI per barrel at Cushing, Oklahoma.
(b) The revenue and margin 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 2006, inclusive.
(e) For the period April to October 2006, inclusive.
(f) For the period January to March 2005, inclusive.
(g) For the period January to May 2006, inclusive.
(h) For the period January to September 2005, inclusive.
(i) Settlement for applicable forwards occurring within the period April to September 2007.
(j) Settlement for applicable forward was March 2006.

Interest Rate Hedges

The company periodically enters into interest rate swap contracts as part of its risk management strategy to manage its exposure to interest rates. The interest rate swap contracts involve an exchange of floating rate and fixed rate interest payments between the company and investment grade counterparties. The differentials on the exchange of periodic interest payments are recognized in the accounts as an adjustment to interest expense.

The notional amounts of interest rate swap contracts outstanding at December 31, 2006, are detailed in note 5, Long-term Debt.

Fair Value of Hedging Derivative Financial Instruments

The fair value of hedging derivative financial instruments is the estimated amount, based on broker quotes and/ or internal valuation models that the company would receive (pay) to terminate the contracts. Such amounts, which also represent the unrecognized and unrecorded gain (loss) on the contracts, were as follows at December 31:

($ millions)	**2006**	2005
Revenue hedge swaps and collars	**22**	(4)
Margin hedge swaps	**—**	1
Interest rate and cross-currency interest rate swaps	**16**	22
Specific cash flow hedges of individual transactions	**(4)**	5
Fair value of outstanding hedging derivative financial instruments	**34**	24

(c) 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. The financial trading activities are accounted for using the mark-to-market method and as such, all financial instruments are recorded at fair value at each balance sheet date. Physical energy marketing contracts involve activities intended to enhance prices and satisfy physical deliveries to customers. The results of these activities are reported as revenue and as energy trading and marketing expenses in the Consolidated Statements of Earnings. The net pretax earnings (loss) for the years ended December 31 were as follows:

Net Pretax Earnings (Loss)

($ millions)	**2006**	2005	2004
Physical energy contracts trading activity	**41**	15	12
Financial energy contracts trading activity	**(3)**	5	11
General and administrative costs	**(3)**	(3)	(4)
Total	**35**	17	19

The fair value of unsettled (unrealized) energy trading assets and liabilities at December 31 were as follows:

($ millions)	**2006**	2005
Energy trading assets	**16**	82
Energy trading liabilities	**13**	70
Net energy trading assets	**3**	12

Change in Fair Value of Net Assets

($ millions)	**2006**
Fair value of contracts at December 31, 2005	12
Fair value of contracts realized during 2006	**(6)**
Fair value of contracts entered into during the period	**2**
Changes in values attributable to market price and other market changes	**(5)**
Fair value of contracts outstanding at December 31, 2006	**3**

The source of the valuations of the above contracts was based on actively quoted prices and/or internal valuation models.

(d) Counterparty Credit Risk

The company may be exposed to certain losses in the event that counterparties to the 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. The company minimizes this risk by entering into agreements with counterparties, of which substantially all are investment grade. Risk is also minimized through regular management review of credit ratings and potential exposure to such counterparties. At December 31, the company had exposure to credit risk with counterparties as follows:

($ millions)	**2006**	2005
Derivative contracts not accounted for as hedges	**16**	82
Unrecognized derivative contracts accounted for as a hedge	**35**	30
Total	**51**	112

7. ACCRUED LIABILITIES AND OTHER

($ millions)	**2006**	2005
Asset retirement obligations [a]	**704**	489
Employee future benefits liability (see note 8)	**170**	190
Employee and director incentive plans [b]	**143**	110
Deferred revenue	**143**	140
Environmental remediation costs [c]	**26**	33
Other	**28**	43
Total	**1 214**	1 005

(a) Asset Retirement Obligations (ARO)

The asset retirement obligation also includes an additional $104 million in current liabilities (2005 – $54 million). 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)	**2006**	2005
Asset retirement obligations, beginning of year	**543**	476
Liabilities incurred	**286**	71
Liabilities settled	**(54)**	(34)
Accretion of asset retirement obligations	**33**	30
Asset retirement obligations, end of year	**808**	543

The total undiscounted amount of estimated future cash flows required to settle the obligations at December 31, 2006, was approximately $1.7 billion (2005 – $1.2 billion). The liability recognized in 2006 was discounted using the Company's credit-adjusted risk-free rate of 5.5% (2005 – 5.6%). Payments to settle the ARO occur on an ongoing basis and will continue over the lives of the operating assets, which can exceed 35 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

Total employee and director incentive plans also include an additional $32 million in current liabilities (2005 – $4 million).

(c) Environmental Remediation Costs

Total accrued environmental remediation costs also include an additional $17 million in current liabilities (2005 – $14 million). Environmental remediation costs are obligations assumed through the purchase of the Commerce City refineries.

8. 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, 2006, was $1,024 million (2005 – $889 million).*

As required by government regulations, Suncor sets aside funds with an independent trustee to meet certain of these obligations. In addition, commencing in 2005, the company began to fund its unregistered supplementary pension plan and supplementary 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 2006, ***Plan Assets*** *to meet the* ***Benefit Obligation*** *were $616 million (2005 – $479 million).*

The excess of the ***Benefit Obligation*** *over* ***Plan Assets*** *of $408 million (2005 – $410 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, commencing in 2005, 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 an employee 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 in 2004. A valuation of the Canadian plan will be performed in 2007.

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 dependents.

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 **2006**	Pension Benefits 2005	Other Post-retirement Benefits **2006**	Other Post-retirement Benefits 2005
Change in benefit obligation				
Benefit obligation at beginning of year	**745**	624	**144**	128
Service costs	**44**	32	**5**	5
Interest costs	**40**	38	**8**	6
Plan participants' contributions	**4**	3	**—**	—
Acquisition [(a)]	**—**	1	**—**	1
Foreign exchange	**(2)**	—	**—**	—
Actuarial loss	**67**	75	**5**	8
Benefits paid	**(32)**	(28)	**(4)**	(4)
Benefit obligation at end of year [(b), (e)]	**866**	745	**158**	144
Change in plan assets [(c)]				
Fair value of plan assets at beginning of year	**479**	399	**—**	—
Actual return on plan assets	**60**	41	**—**	—
Employer contributions	**103**	61	**—**	—
Plan participants' contributions	**4**	3	**—**	—
Benefits paid	**(30)**	(25)	**—**	—
Fair value of plan assets at end of year [(e)]	**616**	479	**—**	—
Net unfunded obligation	**(250)**	(266)	**(158)**	(144)
Items not yet recognized in earnings:				
Unamortized net actuarial loss [(d)]	**177**	167	**52**	53
Unamortized past service costs	**—**	—	**(23)**	(26)
Accrued benefit liability	**(73)**	(99)	**(129)**	(117)
Current liability	**(46)**	(37)	**(3)**	(3)
Long-term liability	**(44)**	(76)	**(126)**	(114)
Long-term asset	**17**	14	**—**	—
Total accrued benefit liability	**(73)**	(99)	**(129)**	(117)

(a) In 2005, in connection with the acquisition of the Colorado Refining Company, the company assumed pension obligations of $1 million and other post-retirement benefit obligations of $1 million. No pension plan assets were acquired.

(b) Obligations are based on the following assumptions:

(per cent)	Pension Benefit Obligations **2006**	Pension Benefit Obligations 2005	Other Post-retirement Benefits Obligation **2006**	Other Post-retirement Benefits Obligation 2005
Discount rate	**5.00**	5.00	**5.00**	5.00
Rate of compensation increase	**5.00**	4.50	**4.75**	4.25

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	(5)	5	(18)	21	9	(8)
Increase (decrease) to benefit obligation	—	—	(136)	161	35	(31)

In order to measure the expected cost of other post-retirement benefits, a 9.5% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2006 (2005 – 10%; 2004 – 11.5%). It is assumed that this rate will decrease by 0.5% annually, to 5% by 2015, 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)

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

(d) 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 (2005 – 11 years; 2004 – 12 years), and over the expected average future service life to full eligibility age of 10 years for other post-retirement benefits (2005 – 9 years; 2004 – 12 years).

(e) 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)	**2006**	2005	**2006**	2005
Partially funded plans	**866**	745	**—**	—
Unfunded plans	**—**	—	**158**	144
Benefit obligation at end of year	**866**	745	**158**	144

Components of Net Periodic Benefit Cost [(a)]

	Pension Benefits			Other Post-retirement Benefits		
($ millions)	**2006**	2005	2004	**2006**	2005	2004
Current service costs	**44**	32	25	**5**	5	5
Interest costs	**40**	38	34	**8**	6	7
Expected return on plan assets [(b)]	**(32)**	(28)	(25)	**—**	—	—
Amortization of net actuarial loss	**28**	21	19	**1**	1	1
Net periodic benefit cost recognized [(c)]	**80**	63	53	**14**	12	13

Components of Net Incurred Benefit Cost [(a)]

	Pension Benefits			Other Post-retirement Benefits		
($ millions)	**2006**	2005	2004	**2006**	2005	2004
Current service costs	**44**	32	25	**5**	5	5
Interest costs	**40**	38	34	**8**	6	7
Actual (return) loss on plan assets [(b)]	**(60)**	(41)	(33)	**—**	—	—
Actuarial (gain) loss	**67**	75	21	**5**	8	4
Net incurred benefit cost	**91**	104	47	**18**	19	16

(a) 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.

(b) 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.

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

	Pension Benefit Expense			Other Post-retirement Benefits Expense		
(per cent)	**2006**	2005	2004	**2006**	2005	2004
Discount rate	**5.00**	5.75	6.00	**5.00**	5.75	6.00
Expected return on plan assets	**6.50**	6.75	7.00	**N/A**	N/A	N/A
Rate of compensation increase	**4.50**	4.50	4.00	**4.25**	4.25	4.00

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, 2006 and 2005, and the target allocation for 2007 are as follows:

	Target Allocation %	Plan Assets %	
	2007	**2006**	2005
Asset Category			
Equities	60	**61**	60
Fixed income	40	**39**	40
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 2007 will be $82 million, including approximately $7 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
2007	35	5
2008	38	5
2009	41	6
2010	44	6
2011	47	7
2012 – 2016	287	44
Total	492	73

Defined Contribution Pension Plan

The company has a Canadian defined contribution plan and two U.S. 401(k) savings plans, under which both the company and employees make contributions. Company contributions and corresponding expense totalled $11 million in 2006 (2005 – $10 million; 2004 – $8 million).

9. 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 next page 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 two rates and the dollar effect is as follows:

	2006		2005		2004	
($ millions)	Amount	%	Amount	%	Amount	%
Federal tax rate	**1 256**	**33**	648	35	577	36
Provincial abatement	**(381)**	**(10)**	(186)	(10)	(161)	(10)
Federal surtax	**43**	**1**	21	1	18	1
Provincial tax rates	**395**	**10**	213	12	188	12
Statutory tax and rate	**1 313**	**34**	696	38	622	39
Adjustment of statutory rate for future rate reductions	**(146)**	**(4)**	(84)	(5)	(84)	(5)
	1 167	**30**	612	33	538	34
Add (deduct) the tax effect of:						
Crown royalties	**125**	**3**	119	6	133	8
Resource allowance [a]	**(42)**	**(1)**	(48)	(2)	(69)	(4)
Large corporations tax	**2**	**—**	23	1	18	1
Tax rate changes on opening future income taxes [b]	**(419)**	**(11)**	—	—	(53)	(3)
Attributed Canadian royalty income	**(23)**	**(1)**	(24)	(1)	(29)	(2)
Stock-based compensation	**18**	**1**	8	—	8	—
Assessments and adjustments	**(9)**	**—**	7	—	—	—
Capital gains	**—**	**—**	(6)	—	(18)	(1)
Other	**16**	**—**	3	—	(2)	—
Income taxes and effective rate	**835**	**21**	694	37	526	33

(a) The resource allowance is 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.

(b) 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.

Effective April 1, 2004, the Alberta provincial corporate tax rate decreased by 1%. In 2003, the Ontario government substantively enacted a general corporate tax rate and manufacturing and processing tax rate increase of 1.5% and 1%, respectively, effective January 1, 2004. Accordingly, in 2004, the company revalued its future income tax liabilities and recognized a decrease in future income tax expense of $53 million.

In 2006, net income tax payments totalled $36 million (2005 – $77 million; 2004 – $50 million).

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

($ millions)	**2006** Current	**2006** Non-current	2005 Current	2005 Non-current
Future income tax assets:				
Employee future benefits	**12**	**—**	7	—
Asset retirement obligations	**32**	**—**	19	—
Inventories	**59**	**—**	67	—
Other	**6**	**—**	(10)	—
	109	**—**	83	—
Future income tax liabilities:				
Excess of book values of assets over tax values	**—**	**4 413**	—	3 490
Deferred maintenance shutdown costs	**—**	**43**	—	51
Employee future benefits	**—**	**(88)**	—	(87)
Asset retirement obligations	**—**	**(203)**	—	(162)
Attributed Canadian royalty income	**—**	**(93)**	—	(86)
	—	**4 072**	—	3 206

10. COMMITMENTS, CONTINGENCIES, VARIABLE INTEREST ENTITIES, AND GUARANTEES

(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, 2006, future minimum amounts payable under these leases and agreements are as follows:

($ millions)	Pipeline Capacity and Energy Services[1]	Operating Leases
2007	242	37
2008	256	32
2009	261	28
2010	264	24
2011	266	20
Later years	3 796	120
	5 085	261

(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, including the shipment of crude oil from Fort McMurray to Hardisty, Alberta. The agreements commenced in 1999 and extend up to 2033. As the initial shipper on one of the pipelines, Suncor's tolls payable are subject to annual adjustments.

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.

(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 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$1.4 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. The excess coverage of US$1.0 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, effective January 1, 2006, the excess coverage has a ceiling of US$40 WTI and effective January 1, 2007, the excess coverage has a lost production maximum of 150,000 barrels per day in addition to the US$40 WTI ceiling. In addition to this coverage, in December 2005, Suncor formed a self-insurance company which offers business interruption coverage for oil sands with a limit of $150 million and a deductible of the greater of 20 days or US$30 million.

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) Variable Interest Entities, Guarantees and Off-balance Sheet Arrangements

At December 31, 2006, the company had various off-balance sheet arrangements with Variable Interest Entities (VIEs) and indemnification agreements with third parties as described below.

The company has a securitization program in place to sell, on a revolving, fully serviced and limited recourse basis, up to $170 million of accounts receivable (2005 – $340 million) having a maturity of 45 days or less, to a third party. The third party is a multiple party securitization vehicle that provides funding for numerous asset pools. As at December 31, 2006, $170 million (2005 – $340 million) in outstanding accounts receivable had been sold under the program. Although the company does not believe it has 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 $72 million in 2006 and no contingent liability or earnings impact have been recorded for this indemnification as the company believes it has 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, 2006, were $170 million and approximately $623 million, respectively. The company recorded an after-tax loss of approximately $2 million on the securitization program in 2006 (2005 – $4 million; 2004 – $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 covers a period of seven years and is accounted for as an operating lease. The company repurchased the equipment in 2006 for $21 million. As at December 31, 2006, the VIE did not have any assets or liabilities.

The company has agreed to indemnify holders of the 7.15% notes, the 5.95% notes and the company's credit facility lenders (see note 5) for added costs relating to taxes, assessments or other government charges or conditions, including any required withholding amounts. Similar indemnity terms apply to the receivables securitization program, and 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.

11. SHARE CAPITAL

(a) 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.

(b) Issued:

	Common Shares	
	Number (thousands)	Amount ($ millions)
Balance as at December 31, 2003	451 184	604
Issued for cash under stock option plans	2 880	41
Issued under dividend reinvestment plan	177	6
Balance as at December 31, 2004	454 241	651
Issued for cash under stock option plans	3 302	74
Issued under dividend reinvestment plan	122	7
Balance as at December 31, 2005	457 665	732
Issued for cash under stock options plan	**2 147**	**52**
Issued under dividend reinvestment plan	**132**	**10**
Balance as at December 31, 2006	**459 944**	**794**

Common Share Options

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 directors that hold options must earn the right to exercise them. This is done by the employee or director 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.

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

(i) EXECUTIVE STOCK PLAN Under this plan, the company granted 538,000 common share options in 2006 (2005 – 518,000; 2004 – 1,346,000) to non-employee directors and certain executives and other senior employees of the company. The exercise price of an option is equal to the market value of the common shares at the date of grant. Options granted have a 10-year life and vest annually over a three-year period.

(ii) SUNSHARE PERFORMANCE STOCK OPTION PLAN During 2006, the company granted 1,637,000 options (2005 – 1,253,000; 2004 – 1,742,000) to eligible permanent full-time and part-time employees, both executive and non-executive, under its employee stock option incentive plan ("SunShare"). Under SunShare, meeting specified performance targets accelerates the vesting of some or all options.

On January 31, 2005, in connection with the achievement of a predetermined performance criterion, 2,062,000 SunShare options vested, representing approximately 25% of the then outstanding unvested options under the SunShare plan. On June 30, 2005, an additional predetermined performance criterion under the SunShare plan was met, resulting in the vesting of 50% of the outstanding, unvested SunShare options on April 30, 2008. The remaining 50% of the outstanding, unvested SunShare options may vest on April 30, 2008 if the final predetermined performance criterion is met. If the performance criterion is not met, the unvested options that have not previously expired or been cancelled will automatically vest on January 1, 2012. Management believes that it is highly likely the final performance criterion will be met and that all unvested SunShare options at April 30, 2008 will vest. During the fourth quarter of 2006, stock-based compensation expense was adjusted to reflect this assumption.

(iii) KEY CONTRIBUTOR STOCK OPTION PLAN In 2004, the Board of Directors approved the establishment of the new Key Contributor stock option plan, under which 5,200,000 options were made available for grant to non-insider senior managers and key employees. Under this plan, the company granted 1,050,000 common share options in 2006 (2005 – 901,000; 2004 – nil) to senior managers and key employees. The exercise price of an option is equal to the market value of the common shares at the date of grant. Options granted have a 10-year life and vest annually over a three-year period.

(iv) DEFERRED SHARE UNITS (DSUs) The company had 1,170,000 DSUs outstanding at December 31, 2006 (1,190,000 at December 31, 2005). 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 2006, 59,000 DSUs were redeemed for cash consideration of $5 million (2005 – 81,000 redeemed for cash consideration of $5 million; 2004 – no redemption). 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, 2006, the total liability related to the DSUs was $107 million (2005 – $87 million), of which $2 million (2005 – $4 million) was classified as current.

During 2006, total pretax compensation expense related to DSU's was $25 million (2005 – $39 million; 2004 – $12 million).

(v) PERFORMANCE SHARE UNITS (PSUs) During 2006, the company issued 397,000 PSUs (2005 – 453,000; 2004 – 354,000) 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 expense recognized for PSUs during 2006 was $42 million (2005 – $21 million; 2004 – $5 million).

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, 2003	21 016	4.11 – 29.85	21.69
Granted	3 088	30.63 – 42.02	34.52
Exercised	(2 880)	4.11 – 40.67	13.94
Cancelled	(537)	23.93 – 41.38	28.71
Outstanding, December 31, 2004	20 687	5.22 – 42.02	24.49
Granted	2 672	36.93 – 71.13	48.27
Exercised	(3 302)	5.22 – 41.38	20.71
Cancelled	(854)	26.14 – 70.53	30.82
Outstanding, December 31, 2005	19 203	5.22 – 71.13	28.12
Granted	**3 224**	**73.36 – 101.79**	**89.95**
Exercised	**(2 147)**	**5.28 – 61.92**	**20.99**
Cancelled	**(471)**	**25.00 – 96.10**	**46.66**
Outstanding, December 31, 2006	**19 809**	**7.77 – 101.79**	**38.48**
Exercisable, December 31, 2006	**8 627**	**7.77 – 94.08**	**24.06**

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)	**2006**	2005	2004
	7 970	10 724	4 342

The following table is an analysis of outstanding and exercisable common share options as at December 31, 2006:

	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 ($)
7.77 – 10.13	577	2	10.01	577	10.01
12.28 – 21.35	2 329	3	15.65	2 329	15.65
23.93 – 30.53	9 604	5	27.16	4 507	26.46
32.24 – 43.65	3 130	7	37.88	1 161	36.86
45.51 – 77.39	1 099	6	57.99	41	53.14
80.00 – 101.79	3 070	7	90.20	12	92.74
Total	19 809	6	38.48	8 627	24.06

(vi) FAIR VALUE OF OPTIONS GRANTED The fair values of all common share options granted are estimated as at the grant date using the Black-Scholes option-pricing model. The weighted-average fair values of the options granted during the year and the weighted-average assumptions used in their determination are as noted below:

	2006	2005	2004
Annual dividend per share	**$0.30**	$0.24	$0.23
Risk-free interest rate	**4.08%**	3.69%	3.79%
Expected life	**5 years**	6 years	6 years
Expected volatility	**29%**	28%	29%
Weighted-average fair value per option	**$29.17**	$15.42	$12.02

Stock-based compensation expense recognized for the year ended December 31, 2006, related to stock option plans was $53 million (2005 – $23 million; 2004 – $25 million).

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

($ millions, except per share amounts)	**2006**	2005	2004
Net earnings attributable to common shareholders – as reported	**2 971**	1 158	1 076
Less: compensation cost under the fair value method for pre-2003 options	**15**	13	47
Pro forma net earnings attributable to common shareholders for pre-2003 options	**2 956**	1 145	1 029
Basic earnings per share			
As reported	**6.47**	2.54	2.38
Pro forma	**6.44**	2.51	2.27
Diluted earnings per share			
As reported	**6.32**	2.48	2.33
Pro forma	**6.29**	2.46	2.23

12. EARNINGS PER COMMON SHARE

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

($ millions)	**2006**	2005	2004
Net earnings attributable to common shareholders	**2 971**	1 158	1 076
(millions of common shares)			
Weighted-average number of common shares	**459**	456	453
Dilutive securities:			
Shares issued under stock-based compensation plans	**11**	10	9
Weighted-average number of diluted common shares	**470**	466	462
(dollars per common share)			
Basic earnings per share [a]	**6.47**	2.54	2.38
Diluted earnings per share [b]	**6.32**	2.48	2.33

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.

13. ACQUISITION OF REFINERY AND RELATED ASSETS

On May 31, 2005, the company acquired all of the issued shares of the Colorado Refining Company, an indirect wholly-owned subsidiary of Valero Energy Corp. for cash consideration of $37 million. Additional payments for working capital and associated inventory brought the total purchase price to $62 million. The acquired company's principal assets are a Commerce City refinery and a products terminal located in Grand Junction, Colorado. The allocation of fair value to the assets acquired and liabilities assumed was $79 million for property, plant and equipment, $30 million for inventory and $41 million for environmental liabilities assumed. The fair value assigned to other liabilities was $6 million. The acquisition was accounted for by the purchase method of accounting.

The results of operations for these assets have been included in the consolidated financial statements from the date of acquisition. The new operations have been reported as part of the Refining and Marketing – U.S.A. segment in the Schedules of Segmented Data.

14. FINANCING EXPENSES (INCOME)

($ millions)	**2006**	2005	2004
Interest on debt	**150**	151	157
Capitalized interest	**(129)**	(119)	(62)
Net interest expense	**21**	32	95
Foreign exchange (gain) on long-term debt	**—**	(37)	(82)
Other foreign exchange (gain) loss	**18**	(10)	11
Total financing expenses (income)	**39**	(15)	24

Cash interest payments in 2006 totalled $146 million (2005 – $149 million; 2004 – $152 million).

15. INVENTORIES

($ millions)	**2006**	2005
Crude oil	**249**	279
Refined products	**200**	124
Materials, supplies and merchandise	**140**	120
Total	**589**	523

The replacement cost of crude oil and refined product inventories exceeded their LIFO carrying value by $243 million (2005 – $202 million) as at December 31, 2006.

During 2006, the company recorded a pretax gain of $6 million related to a permanent reduction in LIFO inventory layers (2005 – $16 million pretax gain).

16. 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)	**2006**	2005	2004
Operating revenues			
Sales to Energy Marketing and Refining – Canada segment joint ventures:			
Refined products	**294**	327	320
Petrochemicals	**136**	279	272

The company has supply agreements with two Energy Marketing and Refining – Canada segment joint ventures for the sale of refined products. The company also has a supply agreement with an Energy Marketing and Refining – Canada segment joint venture for the sale of petrochemicals.

At December 31, 2006, amounts due from Energy Marketing and Refining – Canada segment joint ventures were $20 million (2005 – $22 million).

Sales to and balances with Energy Marketing and Refining – Canada segment joint ventures are established and agreed to by the various parties and approximate fair value.

17. SUPPLEMENTAL INFORMATION

($ millions)	2006	2005	2004
Export sales [(a)]	**810**	648	693
Exploration expenses			
Geological and geophysical	**51**	22	33
Other	**1**	1	1
Cash costs	**52**	23	34
Dry hole costs	**52**	33	21
Cash and dry hole costs [(b)]	**104**	56	55
Leasehold impairment [(c)]	**2**	13	8
	106	69	63
Taxes other than income taxes			
Excise taxes [(d)]	**538**	482	496
Production, property and other taxes	**57**	47	44
	595	529	540
Allowance for doubtful accounts	**4**	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 exploration expenses in the Consolidated Statements of Earnings.

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

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

18. 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	2006	2005	2004
Net earnings as reported, Canadian GAAP		**2 971**	1 158	1 076
Adjustments				
Derivatives and hedging activities	(a)	**11**	83	92
Stock-based compensation	(b)	**(19)**	(26)	(10)
Income tax expense		**(3)**	(28)	(27)
Net earnings from continuing operations, U.S. GAAP		**2 960**	1 187	1 131
Cumulative effect of change in accounting principles, net of income taxes of $2 (2005 – $nil; 2004 – $nil)	(b)	**(4)**	—	—
Net earnings, U.S. GAAP		**2 956**	1 187	1 131
Derivatives and hedging activities, net of income taxes of $3 (2005 – $70; 2004 – $35)	(a)	**6**	140	(67)
Minimum pension liability, net of income taxes of $20 (2005 – $8; 2004 – $3)	(c)	**39**	(15)	5
Unfunded pension obligation, net of income taxes of $60	(c)	**(127)**	—	—
Foreign currency translation adjustment	(d)	**10**	(26)	(29)
Comprehensive income, U.S. GAAP		**2 884**	1 286	1 040

per common share (dollars)	2006	2005	2004
Net earnings per share from continuing operations, U.S. GAAP			
Basic	**6.45**	2.60	2.50
Diluted	**6.29**	2.55	2.45
Net earnings per share, U.S. GAAP			
Basic	**6.44**	2.60	2.50
Diluted	**6.29**	2.55	2.45

The application of U.S. GAAP would have the following effects on the Consolidated Balance Sheets as reported:

		December 31, 2006		December 31, 2005	
	Notes	As Reported	U.S. GAAP	As Reported	U.S. GAAP
Current assets		**2 302**	**2 302**	1 916	1 916
Property, plant and equipment, net		**16 189**	**16 189**	12 966	12 966
Deferred charges and other	(a,c)	**290**	**316**	267	298
Total assets		**18 781**	**18 807**	15 149	15 180
Current liabilities		**2 158**	**2 158**	1 935	1 935
Long-term borrowings	(a)	**2 385**	**2 398**	3 007	3 029
Accrued liabilities and other	(b,c)	**1 214**	**1 430**	1 005	1 092
Future income taxes	(a,c)	**4 072**	**4 002**	3 206	3 179
Share capital	(b)	**794**	**842**	732	780
Contributed surplus	(b)	**100**	**153**	50	88
Cumulative foreign currency translation	(d)	**(71)**	**—**	(81)	—
Retained earnings	(a,b)	**8 129**	**8 026**	5 295	5 207
Accumulated other comprehensive income	(a,c,d)	**—**	**(202)**	—	(130)
Total liabilities and shareholders' equity		**18 781**	**18 807**	15 149	15 180

(a) Derivative Financial Instruments

The company accounts for its derivative financial instruments under Canadian GAAP as described in note 6. Financial Accounting Standards Board Statement (Statement) 133 "Accounting for Derivative Instruments and Hedging Activities," as amended by Statements 138 and 149 (the Standards), establishes U.S. GAAP accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. Generally, all derivatives, whether designated in hedging relationships or not, and excluding normal purchases and normal sales, are required to be recorded on the balance sheet at fair value. If the derivative is designated as a fair value hedge, changes in the fair value of the derivative and changes in the fair value of the hedged item attributable to the hedged risk each period are recognized in the Consolidated Statements of Earnings. If the derivative is designated as a cash flow hedge, the effective portions of the changes in fair value of the derivative are initially recorded in other comprehensive income (OCI) each period and are recognized in the Consolidated Statements of Earnings when the hedged item is recognized. Accordingly, 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 earnings statement caption as the hedged item.

The determination of hedge effectiveness and the measurement of hedge ineffectiveness for cash flow hedges is based on internally derived valuations. The company uses these valuations to estimate the fair values of the underlying physical commodity contracts.

Commodity Price Risk

As described in note 6, Suncor manages crude price variability by entering into WTI derivative transactions and has historically, in certain instances, combined U.S. dollar WTI derivative transactions and Canadian/U.S. foreign exchange derivative contracts. As at December 31, 2006, the company had hedged a portion of its forecasted Canadian and U.S. dollar denominated cash flows subject to U.S. dollar WTI commodity price risk for 2007 and 2008.

U.S. GAAP requires the company to consider all cash flows arising from forecasted Canadian dollar denominated crude oil sales when measuring the ineffectiveness of its cash flow hedges. In periods of significant Canadian/U.S. dollar foreign exchange fluctuations, material hedge ineffectiveness can result from unhedged foreign exchange exposures. This ineffectiveness arises despite the company's assessment that its U.S. dollar WTI hedging instruments are highly effective in achieving offsetting changes in cash flows attributable to its forecasted Canadian dollar denominated crude oil sales.

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 (2005 – $2 million ineffectiveness relating to 2006 and 2007 forecasted cash flows). The net earnings impact of this ineffectiveness will not be recognized for Canadian GAAP purposes until the related forecasted sales occur.

Interest Rate Risk

The company periodically enters into derivative financial instrument contracts such as interest rate swaps as part of its risk management strategy to minimize exposure to changes in cash flows of interest-bearing debt. At December 31, 2006, the company had interest rate derivatives classified as fair value hedges outstanding for up to five years relating to fixed rate debt.

Non-designated Hedging Instruments

In 1999, the company sold inventory and subsequently entered into a derivative contract with an option to repurchase the inventory at the end of five years. The company realized an economic benefit as a result of liquidating a portion of its inventory. The derivative did not qualify for hedge accounting as the company did not have purchase price risk associated with the repurchase of the inventory. This derivative did not represent a U.S. GAAP difference as the company recorded this derivative at fair value for Canadian purposes. The inventory was repurchased in 2004.

Accumulated OCI and U.S. GAAP Net Earnings Impacts

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

($ millions)	**2006**	2005
OCI attributable to derivatives and hedging activities, beginning of the period, net of income taxes of $1 (2005 – $69)	**2**	(138)
Current period net changes arising from cash flow hedges, net of income taxes of $4 (2005 – $2)	**9**	(3)
Net hedging losses at the beginning of the period reclassified to earnings during the period, net of income taxes of $1 (2005 – $72)	**(3)**	143
OCI attributable to derivatives and hedging activities, end of period, net of income taxes of $4 (2005 – $1)	**8**	2

For the year ended December 31, 2006, assets increased by $26 million and liabilities increased by $13 million as a result of recording all derivative instruments at fair value in accordance with U.S. GAAP.

The earnings gain associated with realized and unrealized hedge ineffectiveness on derivative contracts designated as cash flow hedges during the period was $5 million, net of income taxes of $3 million (2005 – loss of $3 million, net of income taxes of $2 million; 2004 – loss of $130 million, net of income taxes of $66 million).The company estimates that $2 million of after-tax hedging gains will be reclassified from OCI to current period earnings within the next 12 months as a result of forecasted sales occurring.

For the year ended December 31, 2006, U.S. GAAP net earnings increased by $7 million, net of income taxes of $4 million (2005 – increased net earnings of $55 million, net of income taxes of $28 million; 2004 – increased net earnings of $65 million, net of income taxes of $27 million) to reflect the impact of the above items.

(b) Stock-based Compensation

On January 1, 2006, the company adopted the U.S. Financial Accounting Standards Board (FASB) Statement 123(R) "Share-based Payment," using the modified-prospective approach. SFAS 123(R) allows the company to expense 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. After adoption of SFAS 123(R), our PSUs for U.S. GAAP have been measured using a Monte Carlo Simulation approach to determine fair value. This change results in a cumulative effect of a change in accounting policy of $4 million, net of income taxes of $2 million. The impact on net earnings for the year ended December 31, 2006, is an increase in stock-based compensation expense of $3 million, 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. SFAS 123(R) requires the immediate recognition of expense related to the unvested portion of the company's pre-2003 options. This resulted in an increase to stock-based compensation expense of $15 million (there was no impact on income taxes) for the year ended December 31, 2006.

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

In September 2006, FASB issued SFAS 158 "Employers Accounting for Defined Benefit and Other Post-retirement Plans." The standard requires the recognition of the overfunded or underfunded status of a defined benefit post-retirement plan (other than a multi-employer plan) as an asset or liability on the balance sheet. The changes to funded status in the year are recorded through comprehensive income, net of tax. This standard has been applied prospectively effective December 31, 2006, as retrospective application is not permitted.

For the current year up to the adoption of SFAS 158 on December 31, 2006, and for prior year comparative balances previously disclosed under U.S. GAAP, recognition of an additional minimum pension liability is required when the accumulated benefit obligation exceeds the fair value of plan assets to the extent that such excess is greater than accrued pension costs otherwise recorded. For the purpose of determining the additional minimum pension liability, the accumulated benefit obligation does not incorporate projections of future compensation increases in the determination of the obligation. No such adjustment is required under Canadian GAAP. As required under SFAS 158, the minimum pension liability adjustment from prior years is reversed in the current year.

At December 31, 2006, the company would have recognized a minimum pension liability of $35 million (2005 – $87 million), an intangible asset of $16 million (2005 – $9 million) and an accumulated other comprehensive loss of $12 million, net of income taxes of $7 million (2005 – $51 million, net of income taxes of $27 million). Other comprehensive income for the year ended December 31, 2006, would have increased by $39 million, net of income taxes of $20 million (2005 – a decrease of $15 million, net of taxes of $8 million; 2004 – an increase in other comprehensive income of $5 million, net of income taxes of $3 million).

Under U.S. GAAP, the impact on future benefit obligations recorded to the balance sheet as at December 31, 2006, as a result of adopting SFAS 158 are as follows:

- Unfunded pension benefits – $177 million
- Unfunded other post-retirement benefits – $29 million

In total, other comprehensive income was decreased by $139 million, net of income taxes at December 31, 2006.

Accumulated OCI and U.S. GAAP Net Earnings Impacts

($ millions)	**2006**	2005
OCI attributable to defined benefit pension and other post-retirement plans, beginning of period, net of income taxes of $27 million (2005 – $19 million)	**(51)**	(36)
Minimum pension liability, net of income taxes of $20 million (2005 – $8 million)	**39**	(15)
Reversal of minimum pension liability upon adoption of SFAS 158, net of income taxes of $7 million	**12**	—
Unamortized net actuarial loss, net of income taxes of $74 million	**(155)**	—
Unamortized past service costs, net of income taxes of $7 million	**16**	—
OCI attributable to defined benefit pension and other post-retirement plans, end of period, net of income taxes of $67 million (2005 – $27 million)	**(139)**	(51)

Total amount included in accumulated OCI expected to be recognized as components of net periodic benefit cost during 2007 are as follows:

- Amortization of net actuarial loss – $29 million
- Amortization of past service costs – $nil

(d) Cumulative Foreign Currency Translation

Under Canadian GAAP, foreign currency gains of $10 million (2005 – losses of $26 million; 2004 – losses of $29 million) arising on translation of the company's U.S. based foreign operations have been recorded directly to shareholders' equity. Under U.S. GAAP, these foreign currency translation losses would be included as a component of comprehensive income.

(e) Suspended Exploratory Well Costs

Effective January 1, 2005, Suncor adopted Financial Accounting Standards Board Staff Position 19-1 (FSP 19-1) "Accounting for Suspended Well Costs." FSP 19-1 amended Statement of Financial Accounting Standards No. 19 (FAS 19) "Financial Accounting and Reporting by Oil and Gas Producing Companies," to permit the continued 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. There were no capitalized exploratory well costs charged to expense upon the adoption of FSP 19-1.

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)	**2006**	2005	2004
Balance, beginning of year	**15**	5	1
Additions pending determination of proved reserves	**21**	14	5
Charged to dry hole expense	**—**	(2)	—
Reclassifications to proved properties	**(13)**	(2)	(1)
Balance, end of year	**23**	15	5
Capitalized for a period greater than one year ($ millions)	**2**	1	—
Number of projects that have exploratory well costs capitalized for a period greater than 12 months	**3**	2	—

(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 statements of earnings. 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 downstream operating segments.

In addition, the R&M segment sells finished product and buys 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, are recorded at fair value in "revenue" and "purchases of crude oil and products" in the statements of income in accordance with the consensus for Issue 2 in EITF 04-13.

The purchase/sale of contract amounts included in revenue for 2006, 2005 and 2004 are shown below.

($ millions)	**2006**	2005	2004
Consolidated revenues	**15 829**	11 129	8 705
Amounts included in revenues for purchase/sale contracts with the same counterparty (1)	**5**	16	7

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

Recently Issued Accounting Standards

In September 2006, FASB issued SFAS 157 "Fair Value Measurements." The standard, effective January 1, 2008, establishes a recognized framework for measuring fair value, and expands disclosures relating to fair value inputs. No new fair value measurements are required. This Statement is generally to be applied prospectively and does not have an impact on earnings or financial position.

In June 2006, FASB issued FIN 48 "Accounting for Uncertainty in Income Taxes." The standard, effective January 1, 2007, requires recognition of uncertain tax positions only where positions are determined to be more likely than not, defined as greater than 50%, to be sustained on audit. All tax positions will be required to meet the recognition threshold as of the effective date of this standard, with the cumulative effect of application shown as an adjustment to the opening balance of retained earnings. The effect of this standard has not yet been determined.

Quarterly summary (unaudited)

FINANCIAL DATA

($ millions except per share amounts)	For the Quarter Ended Mar 31 2006	June 30 2006	Sept 30 2006	Dec 31 2006	Total Year 2006	For the Quarter Ended Mar 31 2005	June 30 2005	Sept 30 2005	Dec 31 2005	Total Year 2005
Revenues	**3 858**	**4 070**	**4 114**	**3 787**	**15 829**	2 074	2 385	3 149	3 521	11 129
Net earnings (loss)										
Oil Sands	**720**	**1 109**	**583**	**412**	**2 824**	83	85	225	583	976
Natural Gas	**42**	**60**	**12**	**(5)**	**109**	26	27	24	78	155
Energy Marketing and Refining – Canada	**18**	**63**	**17**	**(12)**	**86**	(3)	5	17	22	41
Refining and Marketing – U.S.A. [c]	**(2)**	**57**	**70**	**43**	**168**	6	31	50	55	142
Corporate and eliminations	**(65)**	**(71)**	**—**	**(80)**	**(216)**	(45)	(65)	(1)	(45)	(156)
	713	**1 218**	**682**	**358**	**2 971**	67	83	315	693	1 158
Per common share										
Net earnings attributable to common shareholders										
Basic	**1.56**	**2.65**	**1.48**	**0.78**	**6.47**	0.15	0.18	0.69	1.52	2.54
Diluted	**1.52**	**2.59**	**1.45**	**0.76**	**6.32**	0.14	0.18	0.67	1.48	2.48
Cash dividends	**0.06**	**0.08**	**0.08**	**0.08**	**0.30**	0.06	0.06	0.06	0.06	0.24
Cash flow from (used in) operations										
Oil Sands	**1 209**	**1 099**	**926**	**668**	**3 902**	248	210	441	979	1 878
Natural Gas	**100**	**65**	**68**	**48**	**281**	83	81	104	144	412
Energy Marketing and Refining – Canada	**51**	**102**	**51**	**13**	**217**	22	26	44	60	152
Refining and Marketing – U.S.A. [c]	**—**	**96**	**118**	**67**	**281**	18	52	82	95	247
Corporate and eliminations	**(46)**	**(42)**	**(10)**	**(50)**	**(148)**	(77)	(64)	(20)	(52)	(213)
	1 314	**1 320**	**1 153**	**746**	**4 533**	294	305	651	1 226	2 476

OPERATING DATA

OIL SANDS

(thousands of barrels per day)

	Mar 31 2006	June 30 2006	Sept 30 2006	Dec 31 2006	Total Year 2006	Mar 31 2005	June 30 2005	Sept 30 2005	Dec 31 2005	Total Year 2005
Production [1]										
Total operations	**264.4**	**267.3**	**242.8**	**266.4**	**260.0**	139.9	128.2	148.2	267.7	171.3
Firebag	**27.4**	**35.0**	**37.2**	**35.1**	**33.7**	18.7	8.7	23.0	26.0	19.1
Sales										
Light sweet crude oil	**119.2**	**124.7**	**84.9**	**113.7**	**110.5**	75.3	48.3	69.9	108.6	73.3
Diesel	**35.1**	**32.9**	**20.7**	**24.0**	**28.2**	11.8	9.0	10.6	30.7	15.6
Light sour crude oil	**121.0**	**99.2**	**125.8**	**126.8**	**118.2**	38.5	54.2	41.7	104.2	59.8
Bitumen	**—**	**8.5**	**6.6**	**9.7**	**6.2**	18.4	9.6	22.3	7.2	16.6
	275.3	**265.3**	**238.0**	**274.2**	**263.1**	144.0	121.1	144.5	250.7	165.3

Quarterly summary (unaudited) (continued)

OPERATING DATA (continued)

	For the Quarter Ended				Total Year	For the Quarter Ended				Total Year
	Mar 31 2006	**June 30 2006**	**Sept 30 2006**	**Dec 31 2006**	**2006**	Mar 31 2005	June 30 2005	Sept 30 2005	Dec 31 2005	2005
OIL SANDS (continued)										
Average sales price (2)										
(dollars per barrel)										
Light sweet crude oil	**69.00**	**78.27**	**78.11**	**64.51**	**71.98**	45.41	39.20	52.08	55.96	49.93
Other (diesel, light sour crude oil and bitumen)	**63.28**	**72.75**	**68.60**	**57.91**	**65.17**	47.31	50.47	59.70	63.84	56.90
Total	**65.75**	**75.34**	**71.99**	**60.65**	**68.03**	46.44	45.98	56.01	60.42	53.81
Total (a)	**65.75**	**75.34**	**71.99**	**60.65**	**68.03**	54.80	57.24	67.95	66.68	62.68
Cash operating costs and total operating costs – Total Operations										
(dollars per barrel sold rounded to the nearest $0.05)										
Cash costs	**15.55**	**15.65**	**21.00**	**22.65**	**18.70**	20.55	23.50	21.65	16.20	19.60
Natural gas	**3.45**	**2.55**	**2.60**	**3.00**	**2.90**	5.40	3.60	6.00	4.65	4.90
Imported bitumen	**0.05**	**0.10**	**0.10**	**—**	**0.10**	0.10	—	—	0.05	0.05
Cash operating costs (3)	**19.05**	**18.30**	**23.70**	**25.65**	**21.70**	26.05	27.10	27.65	20.90	24.55
Firebag start-up costs	**0.90**	**—**	**—**	**—**	**0.20**	—	—	—	0.30	0.10
Total cash operating costs (4)	**19.95**	**18.30**	**23.70**	**25.65**	**21.90**	26.05	27.10	27.65	21.20	24.65
Depreciation, depletion and amortization	**3.90**	**3.80**	**4.30**	**4.25**	**4.05**	6.25	6.75	6.10	3.60	5.30
Total operating costs (5)	**23.85**	**22.10**	**28.00**	**29.90**	**25.95**	32.30	33.85	33.75	24.80	29.95
Cash operating costs and total operating costs – In-situ Bitumen Production Only (excluding upgrading costs)										
Cash costs	**5.70**	**8.50**	**5.55**	**8.05**	**8.95**	8.90	21.50	7.55	6.70	9.15
Natural gas	**7.70**	**8.15**	**7.60**	**9.90**	**8.35**	10.10	16.40	13.25	13.80	13.05
Cash operating costs (6)	**13.40**	**16.65**	**13.15**	**17.95**	**17.30**	19.00	37.90	20.80	20.50	22.20
Firebag start-up costs	**8.50**	**—**	**—**	**—**	**1.70**	—	—	—	2.90	1.00
Total cash operating costs (7)	**21.90**	**16.65**	**13.15**	**17.95**	**19.00**	19.00	37.90	20.80	23.40	23.20
Depreciation, depletion and amortization	**6.90**	**3.75**	**5.55**	**6.20**	**5.55**	4.75	7.60	4.25	4.60	4.90
Total operating costs (8)	**28.80**	**20.40**	**18.70**	**24.15**	**24.55**	23.75	45.50	25.05	28.00	28.10
NATURAL GAS										
Gross production (b)										
Natural gas (millions of cubic feet per day)	**196**	**189**	**191**	**192**	**191**	191	175	200	193	190
Natural gas liquids (thousands of barrels per day)	**2.4**	**2.6**	**2.1**	**2.1**	**2.3**	3.0	2.2	2.2	2.3	2.4
Crude oil (thousands of barrels per day)	**0.8**	**0.9**	**0.7**	**0.5**	**0.7**	0.9	1.0	0.7	0.6	0.8
Total (barrels of oil equivalent per day at 6:1 for natural gas)	**35.9**	**35.1**	**34.6**	**34.7**	**34.8**	35.7	32.4	36.3	35.0	34.8
Average sales price (2)										
Natural gas (dollars per thousand cubic feet)	**9.03**	**6.38**	**6.33**	**6.55**	**7.15**	6.81	7.29	8.32	11.66	8.57
Natural gas (a) (dollars per thousand cubic feet)	**8.75**	**6.22**	**6.13**	**6.40**	**6.95**	6.74	7.26	8.34	11.83	8.59
Natural gas liquids (dollars per barrel)	**51.75**	**60.14**	**53.11**	**44.20**	**44.96**	38.32	52.52	58.00	57.85	50.70
Crude oil – conventional (dollars per barrel)	**60.30**	**74.18**	**84.95**	**51.20**	**74.83**	61.40	63.86	63.77	72.60	64.85

Quarterly summary (unaudited) (continued)

OPERATING DATA (continued)

	For the Quarter Ended				Total Year	For the Quarter Ended				Total Year
	Mar 31 2006	**June 30 2006**	**Sept 30 2006**	**Dec 31 2006**	**2006**	Mar 31 2005	June 30 2005	Sept 30 2005	Dec 31 2005	2005
ENERGY MARKETING AND REFINING – CANADA										
Refined product sales (thousands of cubic metres per day)	**15.3**	**15.4**	**15.2**	**14.9**	**15.1**	15.1	16.1	15.6	14.3	15.2
Utilization of refining capacity (%)	**86**	**89**	**85**	**51**	**78**	91	100	96	95	95
REFINING AND MARKETING – U.S.A. (c)										
Refined product sales (thousands of cubic metres per day)	**11.3**	**16.2**	**16.2**	**14.2**	**14.4**	10.1	12.6	17.3	14.5	13.7
Utilization of refining capacity (%)	**65**	**102**	**104**	**96**	**92**	96	102	104	91	98

(a) Excludes the impact of hedging activities.

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

(c) Refining and Marketing – U.S.A reflects results of operations from assets acquired May 31, 2005.

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 for in-situ operations. Per barrel amounts are based on total production volumes.

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

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

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

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

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)	**2006**	2005 [a]	2004	2003 [a]	2002
Revenues					
Oil Sands	**7 407**	3 965	3 640	3 101	2 655
Natural Gas	**578**	679	567	512	339
Energy Marketing and Refining – Canada	**5 465**	4 363	3 500	2 936	2 508
Refining and Marketing – U.S.A.	**3 128**	2 621	1 495	515	—
Corporate and eliminations	**(749)**	(499)	(497)	(453)	(431)
	15 829	11 129	8 705	6 611	5 071
Net earnings (loss)					
Oil Sands	**2 824**	976	970	895	804
Natural Gas	**109**	155	115	120	34
Energy Marketing and Refining – Canada	**86**	41	80	53	61
Refining and Marketing – U.S.A.	**168**	142	34	18	—
Corporate and eliminations	**(216)**	(156)	(123)	14	(156)
	2 971	1 158	1 076	1 100	743
Cash flow from (used in) operations					
Oil Sands	**3 902**	1 878	1 734	1 794	1 475
Natural Gas	**281**	412	319	298	164
Energy Marketing and Refining – Canada	**217**	152	188	164	112
Refining and Marketing – U.S.A.	**281**	247	59	34	—
Corporate and eliminations	**(148)**	(213)	(287)	(250)	(358)
	4 533	2 476	2 013	2 040	1 393
Capital and exploration expenditures					
Oil Sands	**2 463**	1 948	1 119	953	618
Natural Gas	**458**	363	279	184	163
Energy Marketing and Refining – Canada	**487**	442	228	122	60
Refining and Marketing – U.S.A.	**178**	337	190	31	—
Corporate	**27**	63	31	32	37
	3 613	3 153	1 847	1 322	878
Total assets	**18 781**	15 149	11 774	10 489	8 978
Capital employed [b]					
Short-term and long-term debt, less cash and cash equivalents	**1 871**	2 891	2 159	2 577	3 204
Shareholders' equity	**8 952**	5 996	4 874	3 858	2 838
	10 823	8 887	7 033	6 435	6 042
Less capitalized costs related to major projects in progress	**(2 476)**	(2 175)	(1 467)	(1 122)	(511)
	8 347	6 712	5 566	5 313	5 531
Total Suncor employees (number at year-end)	**5 766**	5 152	4 605	4 231	3 422

Five-year financial summary (unaudited) (continued)

	2006	2005 [a]	2004	2003 [a]	2002
Dollars per common share					
Net earnings attributable to common shareholders	**6.47**	2.54	2.38	2.45	1.66
Cash dividends	**0.30**	0.24	0.23	0.1925	0.17
Cash flow from operations	**9.87**	5.43	4.44	4.54	3.11
Ratios					
Return on capital employed (%) [b], [c]	**40.6**	19.7	18.9	18.7	15.1
Return on capital employed (%) [d]	**30.4**	14.3	16.0	16.3	14.2
Return on shareholders' equity (%) [e]	**39.7**	21.3	24.6	32.9	29.8
Debt to debt plus shareholders' equity (%) [f]	**21.1**	33.8	31.6	43.5	53.2
Net debt to cash flow from operations (times) [g]	**0.4**	1.2	1.1	1.3	2.3
Interest coverage – cash flow basis (times) [h]	**30.5**	16.9	13.7	11.9	8.1
Interest coverage – net earnings basis (times) [i]	**25.5**	12.5	10.8	10.5	6.4

(a) Refining and Marketing – U.S.A. reflects the results of operations since acquisitions on August 1, 2003 and May 31, 2005.

(b) 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).

(c) Net earnings adjusted for after-tax financing expenses (income) for the 12 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 58 of Management's Discussion and Analysis.

(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) 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.

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

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

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

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

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 2006	**June 30 2006**	**Sept 30 2006**	**Dec 31 2006**	Mar 31 2005	June 30 2005	Sept 30 2005	Dec 31 2005
Share ownership								
Average number outstanding, weighted monthly (thousands) [a]	**458 230**	**458 596**	**458 859**	**459 069**	454 911	456 141	456 996	457 429
Share price (dollars)								
Toronto Stock Exchange								
High	**93.85**	**102.18**	**97.12**	**95.00**	50.07	60.24	73.25	76.05
Low	**75.58**	**75.00**	**71.18**	**72.26**	38.76	44.00	57.75	57.00
Close	**89.63**	**90.34**	**80.19**	**91.79**	48.73	57.92	70.42	73.32
New York Stock Exchange – US$								
High	**82.15**	**89.86**	**86.78**	**82.08**	41.70	48.95	62.50	66.00
Low	**64.00**	**67.36**	**63.77**	**64.06**	31.33	35.38	47.40	48.09
Close	**77.02**	**81.01**	**72.05**	**78.91**	40.21	47.32	60.53	63.13
Shares traded (thousands)								
Toronto Stock Exchange	**107 797**	**101 626**	**106 348**	**99 704**	107 080	102 317	108 384	107 502
New York Stock Exchange	**114 031**	**116 492**	**100 714**	**94 676**	84 285	89 244	139 214	175 618
Per common share information (dollars)								
Net earnings attributable to common shareholders	**1.56**	**2.65**	**1.48**	**0.78**	0.15	0.18	0.69	1.52
Cash dividends	**0.06**	**0.08**	**0.08**	**0.08**	0.06	0.06	0.06	0.06

(a) The company had approximately 2,388 holders of record of common shares as at January 31, 2007.

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 who owns at least 10% of the voting shares of the company.

Supplemental financial and operating information (unaudited)

	2006	2005	2004	2003	2002
OIL SANDS					
Production (thousands of barrels per day)	**260.0**	171.3	226.5	216.6	205.8
Sales (thousands of barrels per day)					
Light sweet crude oil	**110.5**	73.3	114.9	112.3	104.7
Diesel	**28.2**	15.6	27.9	26.3	23.0
Light sour crude oil	**118.2**	59.8	75.1	73.3	68.3
Bitumen	**6.2**	16.6	8.4	6.4	9.3
	263.1	165.3	226.3	218.3	205.3
Average sales price (dollars per barrel)					
Light sweet crude oil	**71.98**	49.93	45.60	40.26	37.56
Other (diesel, light sour crude oil and bitumen)	**65.17**	56.90	39.13	33.93	29.58
Total	**68.03**	53.81	42.28	37.19	33.65
Total (a)	**68.03**	62.68	49.78	40.22	36.94
Cash operating costs – total operations (b)	**21.70**	24.55	15.15	13.80	13.30
Total cash operating costs – total operations (b)	**21.90**	24.65	15.45	13.80	13.30
Total operating costs – total operations (b)	**25.95**	29.95	19.05	17.15	16.80
Cash operating costs – in-situ bitumen production (b), (e), (f)	**17.30**	22.20	22.05	—	—
Total cash operating costs – in-situ bitumen production (b), (e), (f)	**19.00**	23.20	28.90	—	—
Total operating costs – in-situ bitumen production (b), (e), (f)	**24.55**	28.10	34.90	—	—
Capital employed excluding major projects in progress	**5 092**	4 472	4 105	4 010	4 464
Return on capital employed (%) (c)	**53.7**	22.7	22.6	21.1	17.4
Return on capital employed (%) (d)	**40.4**	16.3	18.5	17.7	16.2

(a) Excludes the impact of hedging activities.
(b) Dollars per barrel rounded to the nearest $0.05. See definitions on page 106.
(c) See definitions on page 108.
(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.
(f) In-situ bitumen production costs exclude upgrading costs.

Supplemental financial and operating information (unaudited) (continued)

	2006	2005	2004	2003	2002
NATURAL GAS					
Production					
Natural gas (millions of cubic feet per day)					
Gross	**191**	190	200	187	179
Net	**141**	137	147	142	124
Natural gas liquids (thousands of barrels per day)					
Gross	**2.3**	2.4	2.5	2.3	2.4
Net	**1.7**	1.9	1.8	1.7	1.7
Crude oil (thousands of barrels per day)					
Gross	**0.7**	0.8	1.0	1.4	1.5
Net	**0.6**	0.7	0.8	1.1	1.2
Total (thousands of boe [a] per day)					
Gross	**34.8**	34.8	36.8	34.9	33.7
Net	**25.8**	25.3	27.1	26.4	23.6
Average sales price					
Natural gas (dollars per thousand cubic feet)	**7.15**	8.57	6.70	6.42	3.91
Natural gas (dollars per thousand cubic feet) [b]	**6.95**	8.59	6.73	6.42	3.91
Natural gas liquids (dollars per barrel)	**44.96**	50.70	42.82	36.08	29.35
Crude oil – conventional (dollars per barrel)	**74.83**	64.85	50.41	40.29	31.72
Capital employed	**861**	563	448	400	422
Return on capital employed (%) [e]	**15.3**	30.7	27.1	29.2	9.5
Undeveloped landholdings [c]					
Oil and gas (millions of acres)					
Western Canada					
Gross	**1.2**	0.6	0.7	0.5	0.5
Net	**0.7**	0.4	0.5	0.4	0.4
International					
Gross	**0.1**	0.4	0.7	0.9	1.2
Net	**—**	0.2	0.4	0.2	0.7
Net wells drilled [d]					
Exploratory					
Oil	**—**	—	—	—	—
Gas	**3**	8	5	2	2
Dry	**5**	4	5	31	19
Development					
Oil	**1**	1	—	1	—
Gas	**13**	18	16	16	18
Dry	**4**	3	—	4	4
	26	34	26	54	43

(a) 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.
(b) Excludes the impact of hedging activities.
(c) Metric conversion: Landholdings – 1 hectare = approximately 2.5 acres
(d) Excludes interests in 7 net exploratory wells and 18 net development wells in progress at the end of 2006.
(e) See definitions on page 108.

Supplemental financial and operating information (unaudited) (continued)

	2006	2005	2004	2003	2002
ENERGY MARKETING AND REFINING – CANADA					
Refined product sales (thousands of cubic metres per day)					
Transportation fuels					
Gasoline					
Retail	**4.6**	4.5	4.6	4.4	4.5
Other	**3.8**	3.9	4.1	4.2	4.4
Jet fuel	**0.7**	0.9	0.9	0.7	0.4
Diesel	**3.2**	3.3	3.1	3.0	2.9
	12.3	12.6	12.7	12.3	12.2
Petrochemicals	**0.9**	0.7	0.8	0.8	0.6
Heating oils	**0.5**	0.4	0.4	0.5	0.4
Heavy fuel oils	**0.8**	1.0	0.7	0.8	0.6
Other	**0.6**	0.5	0.8	0.6	0.7
	15.1	15.2	15.4	15.0	14.5
Crude oil supply and refining					
Processed at Sarnia refinery					
(thousands of cubic metres per day)	**8.6**	10.6	11.1	10.5	10.6
Utilization of refining capacity (%)	**78**	95	100	95	95
Capital employed excluding major projects in progress	**1 023**	486	512	551	485
Return on capital employed (%) [d]	**12.5**	8.1	14.6	10.3	12.0
Return on capital employed (%) [d], [e]	**7.4**	5.2	13.6	10.3	12.0
Retail outlets [f] (number at year-end)	**374**	374	378	379	384

Supplemental financial and operating information (unaudited) (continued)

	2006	2005	2004	2003	2002
REFINING AND MARKETING – U.S.A. [a]					
Refined product sales (thousands of cubic metres per day)					
Transportation fuels					
Gasoline					
Retail [b]	**0.7**	0.7	0.7	0.7	—
Other	**6.8**	6.2	3.8	3.5	—
Jet fuel	**1.0**	0.8	0.5	0.5	—
Diesel	**3.6**	3.3	2.2	2.3	—
	12.1	11.0	7.2	7.0	—
Asphalt	**1.2**	1.6	1.5	1.7	—
Other	**1.1**	1.1	0.6	0.4	—
	14.4	13.7	9.3	9.1	—
Crude oil supply and refining					
Processed at Denver refinery					
(thousands of cubic metres per day)	**13.1**	12.1	8.8	9.4	—
Utilization of refining capacity (%)	**92**	98	92	98	—
Capital employed excluding major projects in progress	**831**	327	232	270	—
Return on capital employed (%) [d], [h]	**34.2**	49.4	12.2	—	—
Return on capital employed (%) [d], [e], [h]	**22.6**	28.9	11.1	—	—
Retail outlets [g] (number at year-end)	**43**	43	43	43	—

(a) Refining and Marketing – U.S.A. reflects the results of operations since acquisitions on August 1, 2003 and May 31, 2005.

(b) Excludes sales through joint venture interests.

(c) Excludes the impact of hedging activities.

(d) See definitions on page 108.

(e) 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.

(f) Sunoco-branded service stations, other private brands managed by EM&R and EM&R's interest in service stations managed through joint ventures. Outlets are located mainly in Ontario.

(g) Phillips 66-branded service stations. Outlets are primarily located in the Denver, Colorado area.

(h) For 2003, represents five months of operations since acquisition August 1, 2003, therefore no annual ROCE was calculated.

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 2006, Suncor paid an aggregate dividend of $0.30 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/dividend.

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 and special meeting of shareholders will be held at 10:30 a.m. MT on April 26, 2007, at the Metropolitan Centre, 333 Fourth Avenue S.W., Calgary, Alberta. Presentations from the meeting will be web-cast live at www.suncor.com/webcasts.

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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.

There are no significant differences between Suncor's governance practices and those prescribed by the New York Stock Exchange (NYSE), with the exception of the requirements applicable to equity compensation plans. A comprehensive description of Suncor's governance practices, including differences between Toronto Stock Exchange (TSX) and NYSE requirements related to equity compensation plans, 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.

Independence

As of December 31, 2006, Suncor's Board of Directors comprised 12 directors, 11 of whom have been determined by the Board to be independent of management under the guidelines established by the TSX and NYSE. The role of chair is assumed by an independent director and is separate from the role of chief executive officer. All Board committees are comprised entirely of independent directors.

The selection of new nominees for membership on the Board is conducted by the Board Policy, Strategy Review and Governance Committee, comprised solely of independent directors. The selection process includes an annual assessment of the competencies and skills the Board as a whole should possess, and of current director capabilities. The Board Policy, Strategy Review and Governance Committee utilizes the services of executive search consulting firms to assist with the selection process. Ultimately, the committee provides its recommendation to the full Board, which approves a nominee for submission to shareholders for election to the Board.

Additionally, the committee annually assesses and evaluates the overall performance and effectiveness of the Board, its committees, and individual directors. Each year, a confidential questionnaire including a self-assessment and peer review is completed by each director. The resulting data is analyzed by the Board Policy, Strategy Review and Governance Committee, which then reports to the full Board with any recommendations for enhancing or strengthening effectiveness.

Committee Key Responsibilities

Committee	Key Responsibilities
Board Policy, Strategy Review and Governance Committee	Oversees Suncor's values, beliefs and standards of ethical conduct. Reviews key matters pertaining to governance, including organization, composition and effectiveness of the Board. Reviews preliminary stages of key strategic initiatives and projects. Reviews and assesses processes relating to long-range and strategic planning and budgeting.
Human Resources and Compensation Committee	Reviews and ensures Suncor's overall goals and objectives are supported by appropriate executive compensation philosophy and programs. Annually evaluates the performance of the chief executive officer (CEO) against predetermined goals and criteria, and recommends to the Board the total compensation for the CEO. Annually reviews the CEO's evaluation and recommendations for total compensation of the other executive roles, the executive succession planning process and results, and all major human resources programs.
Environment, Health and Safety Committee	Reviews the effectiveness with which Suncor meets its obligations pertaining to environment, health and safety, including the establishment of appropriate policies with regard to legal, industry and community standards and related management systems and compliance.
Audit Committee	Assists the Board in matters relating to Suncor's internal controls, internal and external auditors and the external audit process, oil and natural gas reserves reporting, financial reporting, public communication and certain other key financial matters. Provides an open avenue of communication between management, the internal and external auditors and the Board. Approves Suncor's interim financial statements and management's discussion and analysis.

Share Ownership

The Board has set guidelines for its own, as well as executive share ownership. These guidelines, as well as the amount of shares held by each Board member and named executive are reported annually in Suncor's Management Proxy Circular.

For further information about Suncor's corporate governance practices and the company's code of corporate conduct, visit www.suncor.com or call 1-800-558-9071 to order a copy of Suncor's Management Proxy Circular.

Board of directors

JR Shaw [2,3]

Calgary, Alberta
Chairman of the Board of Directors
Director since 1998

JR Shaw has been the chairman of the Board of Suncor since 2001. He is also the executive chair of Shaw Communications Inc., the company he founded in 1966. Mr. Shaw is also president of the Shaw Foundation and serves as a director of Darian Resources. Mr. Shaw is an Officer of the Order of Canada.

Mel E. Benson [3,4]

Calgary, Alberta
Chair, Environment, Health and Safety Committee
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 also a director of Kanetax Energy Inc., Tenax Energy Inc., Winalta Homes Inc. and Poplar Point Energy. He is active with several charitable organizations including Hull Family Services, the Council for Advancement of Native Development Officers and the Canadian Aboriginal Professional Association. He is also a member of the Board of Governors for the Northern Alberta Institute of Technology and the National Aboriginal Economic Development Board.

Brian A. Canfield [1,2]

Point Roberts, Washington
Director since 1995

Brian Canfield is the chairman of TELUS Corporation, a telecommunications company. Mr. Canfield is also a director and chair of the governance committee of the Canadian Public Accountability Board. In 1998, Mr. Canfield was appointed to the Order of British Columbia. In 2007, he was appointed a Member of the Order of Canada.

Bryan P. Davies [3,4]

Etobicoke, Ontario
Chair, Human Resources and Compensation Committee
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. Prior to that, he was senior vice president of regulatory affairs with the Royal Bank Financial Group. Mr. Davies serves as past chair of the Canadian Merit Scholarship Foundation and a director of the Foundation for International Training.

Brian A. Felesky [1,4]

Calgary, Alberta
Director since 2002

Brian Felesky is counsel to the law firm 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, Fairquest Energy Ltd. and Resin Systems Inc. He is the 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, and board member of the Calgary Stampede Foundation and the Calgary Arts Development Authority. Mr. Felesky is a Member of the Order of Canada.

John T. Ferguson [1,2]

Edmonton, Alberta
Chair, Audit Committee
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. He is a director of the C.D. Howe Institute, 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 the Institute of Corporate Directors.

W. Douglas (Doug) Ford [2,3]

Downers Grove, Illinois
Director since 2004

Doug 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 the company, 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 (Rick) L. George

Calgary, Alberta
Director since 1991

Rick George is the president and chief executive officer of Suncor Energy Inc. Mr. George is also a director of the U.S. offshore and onshore drilling company, GlobalSantaFe Corporation, and chair of the 2008 Governor General's Canadian Leadership Conference. In 2006, he was named a member of the North American Competitiveness Council by Canadian Prime Minister Stephen Harper. He served as chairman of the Canadian Council of Chief Executives from 2003 to 2006.

John R. Huff (2,3)

Houston, Texas
Chair, Board Policy, Strategy Review and Governance Committee
Director since 1998

John Huff is chairman of the board of Oceaneering International Inc., an oil field services company. Mr. Huff is also a director of BJ Services Company and Rowan Companies Inc. He is a member of the National Petroleum Council, and is active in the Houston Museum of Natural Science and St. Luke's Episcopal Hospital System in Houston.

M. Ann McCaig (3,4)

Calgary, Alberta
Director since 1995

Ann McCaig is chair of the Alberta Adolescent Recovery Centre, a trustee of the Killam Estate, chair of the Calgary Health Trust, a director of the Calgary Stampede Foundation and honorary chair of the Alberta Bone and Joint Institute. She is also chancellor emeritus of the University of Calgary and a Member of the Order of Canada. She is past co-chair of the Alberta Children's Hospital Foundation.

Michael W. O'Brien (1,4)

Canmore, Alberta
Director since 2002

Michael O'Brien served as executive vice president, corporate development and chief financial officer of Suncor Energy Inc. before his retirement in 2002. Mr. O'Brien serves on the boards of PrimeWest Energy Inc. and Shaw Communications Inc. and as an advisor to CRA International. As well, he is past chair of the board of trustees for Nature Conservancy of 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)

West Vancouver, British Columbia
Director since 2006

Eira Thomas has been president and chief executive officer of Stornoway Diamond Corporation, a mineral exploration company, since July 2003. Previously, Ms. Thomas was president of Navigator Exploration Corporation and chief executive officer and director of Stornoway Ventures Ltd. She is a director of Strongbow Exploration Inc. and Fortress Minerals Corp. As well, Ms. Thomas is a director of the University of Toronto's Alumni Association, Lassonde Advisory Board of the University of Toronto, Prospectors and Developers Association of Canada and the Northwest Territories and Nunavut Chamber of Mines. She is also a member of the University of Toronto's President's Internal Advisory Council.

(1) Audit Committee
(2) Board Policy, Strategy Review and Governance Committee
(3) Human Resources and Compensation Committee
(4) Environment, Health and Safety Committee

Suncor's most recently filed Form 40-F included, as exhibits, the certifications of our Chief Executive Officer and Chief Financial Officer required by Sections 302 and 906 of the United States Sarbanes-Oxley Act of 2002.

Corporate Officers*

Richard L. George
President and Chief Executive Officer

J. Kenneth Alley
Senior Vice President
and Chief Financial Officer

M. (Mike) Ashar
Executive Vice President,
Refining and Marketing – U.S.A.

David W. Byler
Executive Vice President,
Natural Gas and Renewable Energy

Bart W. Demosky
Vice President and Treasurer

Terrence J. Hopwood
Senior Vice President
and General Counsel

Sue Lee
Senior Vice President,
Human Resources and Communications

Kevin D. Nabholz
Executive Vice President,
Major Projects

Janice B. Odegaard
Vice President,
Associate General Counsel and Corporate Secretary

Thomas L. Ryley
Executive Vice President,
Energy Marketing and Refining – Canada

Jay Thornton
Senior Vice President,
Business Integration

Steven W. Williams
Executive Vice President,
Oil Sands

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. Ashar is president of Suncor Energy (U.S.A.) Inc., Suncor's U.S.-based downstream subsidiary; Mr. Ryley is the president of Suncor's Canada-based downstream subsidiaries, Suncor Energy Marketing Inc. and Suncor Energy Products Inc., respectively; and Mr. Nabholz, Ms. Lee and Mr. Thornton are officers of Suncor Energy Services Inc., which provides major projects management, human resources and communication, business integration and other shared services to the Suncor group of companies.

* This information reflects the positions of officers at December 31, 2006. In March 2007, Suncor announced a restructuring of the company's executive management team. See page 16 for details.

The Dow Jones Sustainability Index (DJSI) follows a best-in-class approach comprising the sustainability leaders from each industry. Suncor has been part of the index since the DJSI was launched in 1999.

As an Imagine Caring Company, Suncor contributes 1% of its domestic pretax profit to registered charities.

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Suncor is committed to working in an environmentally responsible manner.
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SUNCOR
ENERGY

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