500,000 bpd

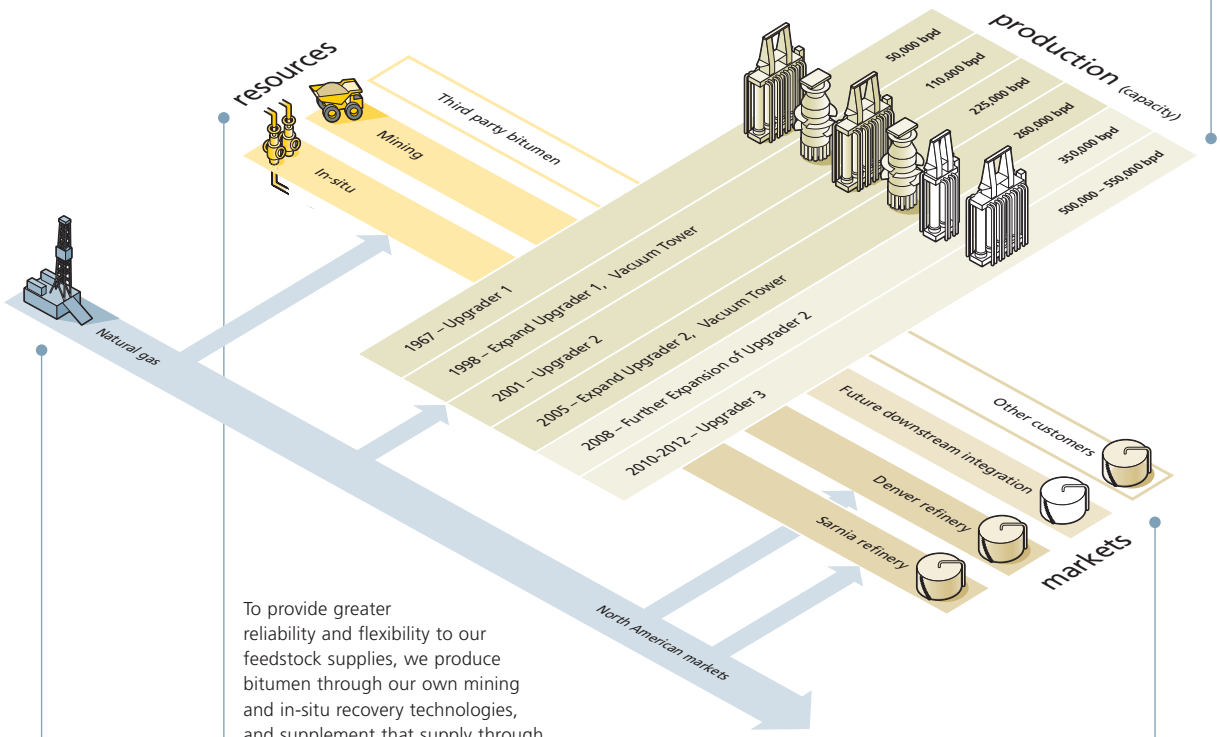
OUR PLANS TO GROW TO HALF A MILLION BARRELS PER DAY IN 2010 TO 2012*

* See page 1

> 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.

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.



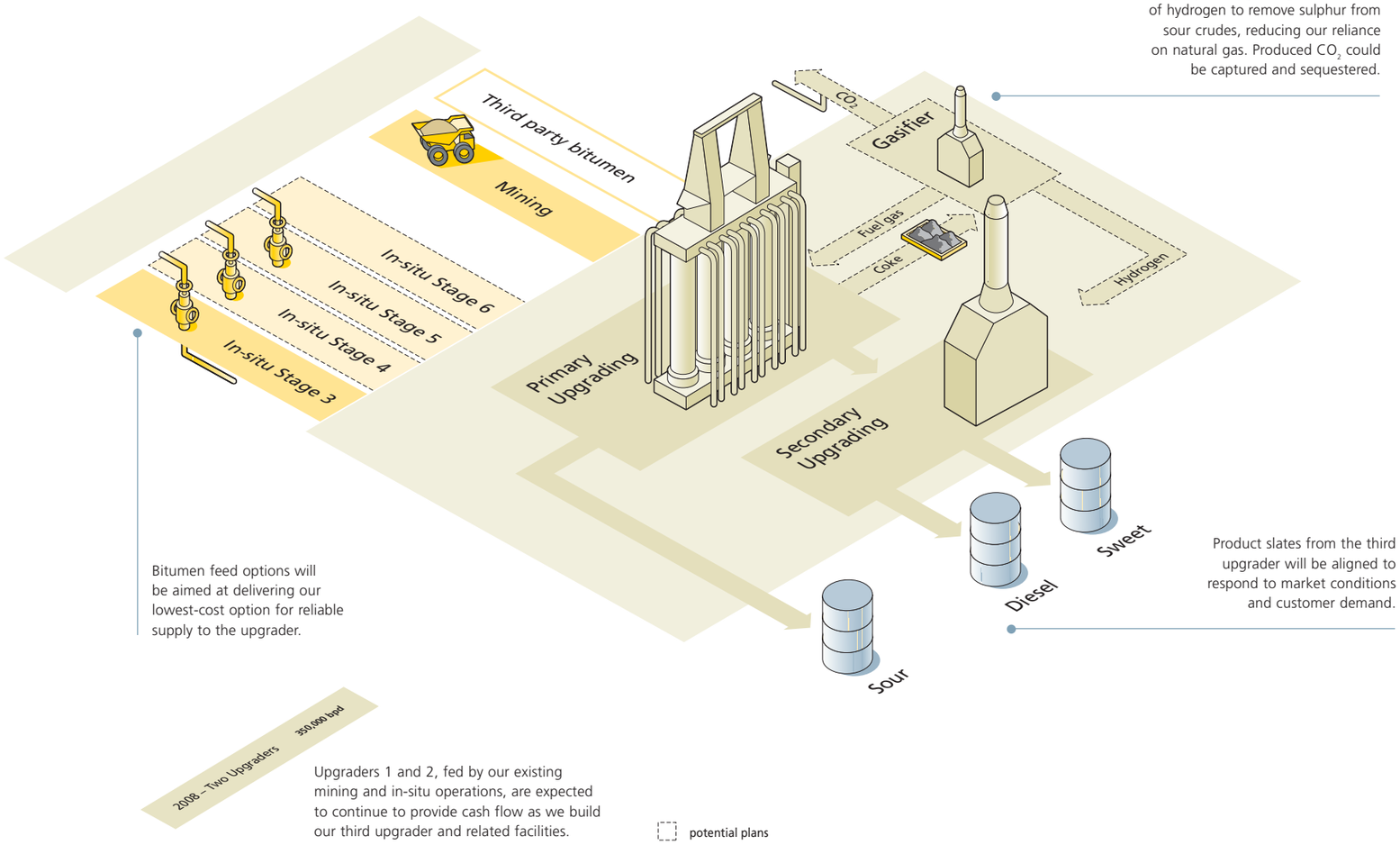
To provide greater reliability and flexibility to our feedstock supplies, we produce bitumen through our own mining and in-situ recovery technologies, and supplement that supply through innovative third-party agreements.

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 are a key part of Suncor's climate change action plan.

In 2006, we reached a new milestone – production of our billionth barrel of synthetic crude oil. As we continue the journey to the next billion barrels, we will maintain the focus on technology, integration and innovation that has made us an industry leader. While our growth strategy is squarely focused on the oil sands, this "pure play" approach does not limit our options. From the mine to the marketplace, we will continue to build alternative approaches into our strategy that allow us to respond to developing technologies and changing market conditions.



Bitumen feed options will be aimed at delivering our lowest-cost option for reliable supply to the upgrader.

Upgraders 1 and 2, fed by our existing mining and in-situ operations, are expected to continue to provide cash flow as we build our third upgrader and related facilities.

Petroleum coke gasification technology could provide an energy supply for upgrading and a source of hydrogen to remove sulphur from sour crudes, reducing our reliance on natural gas. Produced CO_2 could be captured and sequestered.

Product slates from the third upgrader will be aligned to respond to market conditions and customer demand.

> growing responsibly

Suncor is a company that understands the importance of long-term vision – and our vision is to be a sustainable energy company.

That means managing our business in a way that enhances the social and economic benefits we provide, while striving to minimize and mitigate environmental impacts associated with resource development. Suncor adopted this vision of sustainable development in 1992 and began to integrate it into our business strategy. Our efforts to integrate social, economic and environmental considerations into business decisions have forced us to think broadly and in the long term. This helps us reduce and manage risk while building the rewards of our business – for Suncor and our stakeholders.

In 2005, we invested more than $9 million in community and charitable programs and support for innovative training and business development initiatives. We also put the investment plans in place to more than triple our expanding renewable energy business. It's all part of putting our vision to work.

SUNCOR ENERGY INC. is an integrated energy company strategically focused on developing one of the world's largest petroleum resource basins – Canada's Athabasca oil sands. In 1967, we were the first to develop the oil sands on a commercial scale and now, with 38 years of oil sands experience behind us, Suncor has become a major North American energy producer and marketer.

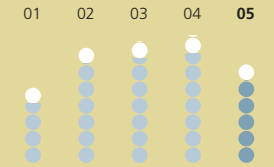
< what 500,000 bpd looks like

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 58 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 56 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" or "the company" mean Suncor Energy Inc., its subsidiaries and joint-venture investments, unless the context otherwise requires. Suncor has provided cost estimates for projects that, in many cases, are still in the early stages of development. These costs are preliminary estimates only. The actual amount is expected to differ and the difference could be material.

FINANCIAL HIGHLIGHTS

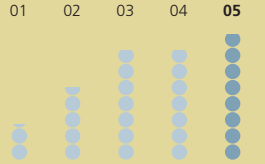
Suncor's strong financial returns are evidence of our ability to generate shareholder value by delivering on strategic growth opportunities.

Production
(thousands of barrels of oil equivalent per day)



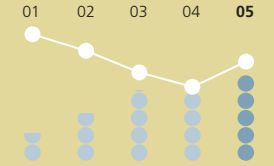
	01	02	03	04	**05**
Natural Gas	33.4	33.7	34.9	36.8	**34.8**
Oil Sands	123.2	205.8	216.6	226.5	**171.3**
Total	156.6	239.5	251.5	263.3	**206.1**

Net Earnings
($ millions)



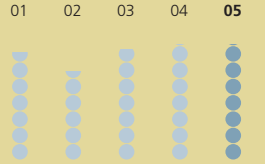
01	02	03	04	**05**
349	720	1 087	1 088	**1 245**

Cash Flow from Operations*/ Net Debt
($ millions)



	01	02	03	04	**05**
Cash flow from operations	799	1 393	2 040	2 013	**2 476**
Net debt	3 678	3 204	2 577	2 159	**2 891**

Return on Capital Employed*
(per cent)



01	02	03	04	**05**
17.8	14.5	18.3	19.0	**20.9**

Excludes major project costs until new assets are brought into operation.

Other Key Indicators

Year ended December 31 ($ millions)	**2005**	2004	2003	2002	2001
Financial					
Revenues	**11 086**	8 665	6 611	5 071	4 326
Capital and exploration expenditures	**3 153**	1 847	1 322	878	1 694
Total assets	**15 351**	11 841	10 540	9 046	8 467
Dollars per Common Share					
Net earnings attributable to common shareholders – basic	**2.73**	2.40	2.42	1.61	0.78
Net earnings attributable to common shareholders – diluted	**2.67**	2.36	2.26	1.59	0.77
Cash flow from operations	**5.43**	4.44	4.53	3.11	1.79
Cash dividends	**0.24**	0.23	0.1925	0.17	0.17
Market Price of Common Stock at December 31 (closing)					
Toronto Stock Exchange (Cdn$)	**73.32**	42.40	32.50	24.70	26.20
New York Stock Exchange (US$)	**63.13**	35.40	25.06	15.67	16.45
Key Ratios					
Debt to debt plus shareholders' equity (%)	**33.3**	31.4	43.2	52.7	62.4
Net debt to cash flow from operations (times)	**1.2**	1.1	1.3	2.3	4.6
Return on shareholders' equity (%)	**22.5**	24.7	32.1	28.2	16.8

* Non GAAP measures. See page 56 for more details.

Suncor has four major business divisions in Canada and the United States and more than 5,000 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.

> connecting to large markets

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 newer 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 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 its 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.

*Sunoco 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.

What does 500,000 barrels per day look like? It could be seen as 20% of Canada's current crude oil production, or twice the volume of crude oil that's imported into the U.S. Rocky Mountain region. At Suncor Energy, we see 500,000 barrels per day as a production target that will support our continuing leadership role in the oil sands. And it's a picture that is becoming increasingly clear as we continue to deliver the Suncor strategy.

Rick George
president and
chief executive officer

Growing Strategically

Our strategy is built on the strengths of the company's resource base, production assets and market access. With Suncor leases containing an estimated 14 billion barrels of reserves and resources*, we have long believed the oil sands have world-class development potential. While recent interest in the oil sands has driven up land prices and pushed exploration to the fringes of the Athabasca basin, Suncor has realized the advantage of being "first in" to quietly assemble nearly 200,000 hectares of leases.

Building on those resources is our second strategic pillar: a manufacturing approach to producing crude oil that leverages substantial existing assets and 38 years of experience in oil sands production technology. There is a saying that "the best time to plant a tree is 40 years ago and the second best time is now." We've done both and today we enjoy the benefits of a capital asset base and on-the-job experience that are producing the barrels and cash flow to support our future growth plans.

The third pillar of Suncor's integrated strategy is access to markets. As we expand production, we are also expanding our market connections to build a stable customer base in Canada and the United States, the world's largest energy market. Our portfolio approach, with a range of crude oil products, contracts and destinations helps us to navigate a changing energy marketplace. Refining and retail operations in Colorado and Ontario take these consumer-connections a step further, providing internal markets in periods of excess capacity, while allowing us to capture further value from the fuels, distillates and petrochemicals we produce. Our natural gas operations also play a role in our market strategy, providing Suncor with a 'price hedge' that has earned steady returns and more than compensated for the cost of natural gas used in our operations.

This three-part strategy, together with a focus on innovation, technology and a long-term vision of managing our environmental and social performance, has driven our past successes and will guide our future plans as we work toward the goal of producing half a million barrels per day (bpd) in the next four to six years.

2005 Highlights

It may be an understatement to describe 2005 as a year that ended very differently than it began. As shareholders know, we got off to a challenging start with a fire at our oil sands facility that crippled one of our two oil sands upgraders for about nine months, reducing annual oil sands production to about 171,000 bpd from the normal capacity of 225,000 bpd and increasing per barrel costs. While the recovery and rebuild was a trying period for all of us and the focus of much of our attention, there were many bright spots in 2005 that have emerged from the eclipse of the fire.

First was the recovery itself. All rebuild work was completed on schedule with the plant returning to full production capacity in September. Despite the cold weather early in the year and intense levels of activity, Suncor's oil sands upgrading team continued an uninterrupted streak

* See pages 11 and 34 to 37

of 10.5 million person-hours without a lost time injury – a great accomplishment in its own right and also a key indicator of our focus on attention to detail and operational excellence.

While recovery work was underway, Suncor also met two important milestones at our oil sands operation: a complete maintenance shutdown of Upgrader 2 and the commissioning of a $450 million expansion to the facility – completed on schedule and on budget. That expansion increased production capacity by more than 15% to 260,000 barrels per day. These two key accomplishments provide the foundation for strong and steady production in 2006.

Setting the stage for 2006 was also the theme in our downstream operations. At Commerce City, we became the largest refining operation in the U.S. Rockies with the acquisition in May of a neighbouring refinery from Valero Energy Corporation. The 30,000 bpd step-change in refining capacity provides a market connection that nearly matches the step-change in oil sands production capacity reached in 2005. Last year also saw Suncor reach peak construction activity on work to modify our Commerce City and Sarnia refineries to meet low-sulphur fuels regulations and to enable both facilities to process increased volumes of sour crude.

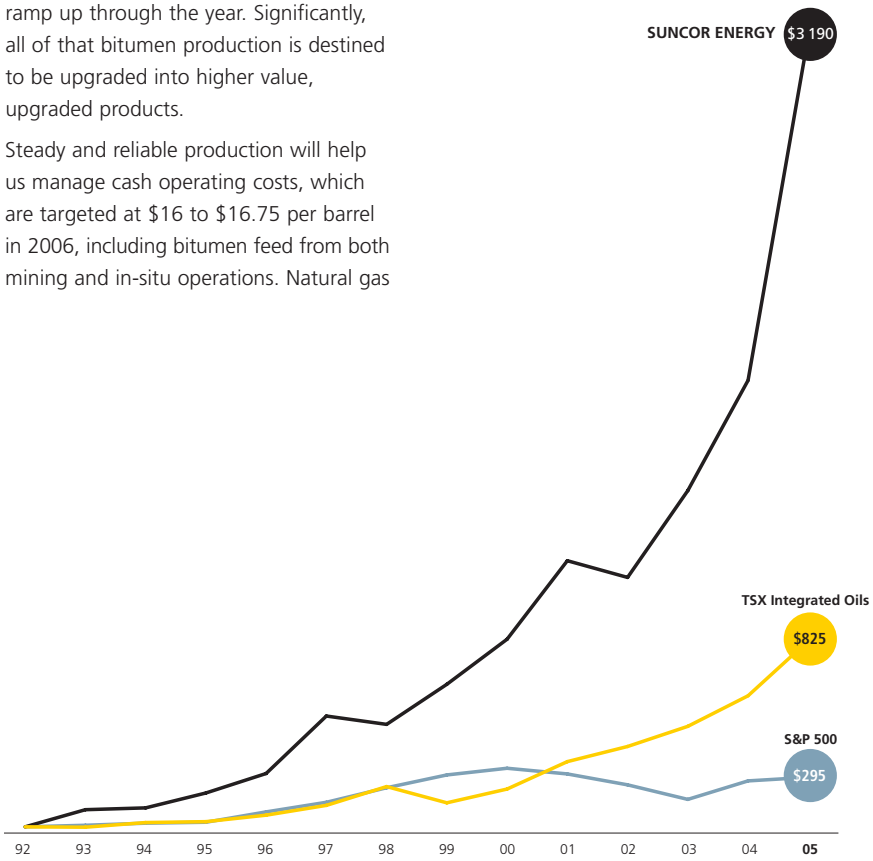
With a challenging but ultimately successful year behind us, Suncor is now focused on delivering solid results to shareholders in 2006, and putting together the pieces for our next phases of growth. While we have enjoyed strong commodity prices, we are concerned about inflationary pressures and workforce availability. Costs and labour supplies are not entirely within our control, but we will continue to focus on areas we can control: ensuring safe, reliable operations, managing operating costs, applying new technologies, expanding our integrated operations and maintaining a strong balance sheet.

Plans and Priorities

Steady, reliable production. With newly expanded upgrading operations and no planned maintenance, we are targeting record annual oil sands production of 260,000 bpd in 2006. An increasing portion of the bitumen to feed the upgrader is expected to come from our in-situ operations, where Firebag stage one is expected to hit full production capacity while stage two continues to ramp up through the year. Significantly, all of that bitumen production is destined to be upgraded into higher value, upgraded products.

Steady and reliable production will help us manage cash operating costs, which are targeted at $16 to $16.75 per barrel in 2006, including bitumen feed from both mining and in-situ operations. Natural gas prices, however, remain a wildcard and may impact those targets, particularly as they relate to the in-situ production part of our cost equation. Our response to that risk is twofold:

First, with our own natural gas production, we will continue to focus on high-impact, deep gas prospects. Our goal is to increase natural gas production by about 10% to 205 to 210 million cubic feet per day in 2006, and between 3% and 5% annually over the longer term.



> delivering value

EQUITY APPRECIATION An investment of $100 in Suncor on December 31, 1992 – the year we became publicly traded – would have grown to $3,190 by the end of 2005.

Second, we are gaining experience with our in-situ operations and actively working on new technologies. As these processes move from development to deployment, we believe production costs should decrease. That optimism is, however, tempered with pragmatism and we will continue to plan a flexible strategy that leaves open all options for bitumen feed as our operations grow.

Build for future growth. The next major milestone on the journey to half a million barrels per day is in 2008, when we are expecting to increase production capacity by a further 35% to 350,000 bpd. Fabrication and transportation of the cokers that form the centrepiece of this expansion is complete and the work at our upgrading facility continues on schedule and on budget.

On the bitumen supply side, we expect to substantially complete engineering for the Steepbank mine extension and extraction facilities. We're also looking forward to preliminary results from a pilot project using mobile crusher technology that we hope will eventually result in reduced operating costs in our mines. That technology may find a home in two undeveloped leases, north and west of our current operations, where we are conducting drilling this year to further delineate the resource base.

As we look further to the future, a regulatory hearing is expected in 2006 regarding our plans for increasing oil sands production to half a million barrels per day in 2010 to 2012, while engineering for that expansion progresses to the design specification stage. We have worked with a wide variety of stakeholders in preparing our application and are confident we are on track to meet regulatory and stakeholder expectations.

In the downstream, the Commerce City refinery will undergo a major maintenance shutdown early in the year to support operational reliability and to tie in equipment that will enable it to process 10,000 to 15,000 bpd of oil sands sour crude blends. We are also planning a major shutdown for the Sarnia refinery that will support plans to convert the operation in 2007 into an oil sands-optimized facility, capable of processing 40,000 bpd of sour crude blends.

Control capital costs and maintain a strong balance sheet. Major growth plan announcements have become common in the energy industry and in the current high commodity price environment, it appears that many industry-watchers have grown accustomed to multibillion dollar projects and forgotten the risks involved. We have not. Suncor has learned from past challenges and we've continued to develop the in-house project management skills that are critical to our future success. Since 2001, our record of "on time and on budget" project delivery has been strong. It's a record we hope to maintain as we continue to benefit from the most experienced engineering, procurement and construction team in the oil sands industry and our six point plan for managing capital growth. (see sidebar left)

While we keep a keen eye on budgets and schedules, we will also be watching the financial foundation that supports our capital plans. With planned capital investment of about $3.5 billion per year over the next several years, tight management of debt and reducing cash flow risks through strategic hedging programs will be key to maintaining a strong balance sheet.

6 point plan to > 500,000 bpd

As we expand our operations, Suncor is planning capital investment of $3.5 billion per year. To keep capital costs under control as we grow, Suncor is following a six-point plan:

- **Maintaining a Suncor organization** to manage growth projects to ensure the best people and best practices are always at work.
- **Taking a staged approach to growth** allowing us to control the size of projects and apply what we've learned to future stages.
- **Keeping the parts small** with no project components exceeding $1 billion allowing better control of both budgets and schedules.
- **Drawing from a variety of workforce options** for major expansion projects, which helps manage demand for skilled trades.
- **Building long-term relationships** with "suppliers of choice" to improve our service and supply chain management.
- **Eliminating reworks** by meeting advanced engineering milestones before fabrication or construction begins.

Addressing Labour Supply Risks

Well-managed operations, investment in new technology, superior project management and a strong balance sheet – all are critical to our growth plans. But just as important is training, attracting and retaining the skilled workers we need to put those plans into action.

The issue of workforce shortages is a serious threat to Canada's economic health. Suncor and the oil sands industry are acutely aware of this risk. Shortages of skilled labour impact schedules and costs, which could derail or delay important projects and jeopardize the economic benefits they generate. All sectors – oil sands, forestry, construction, manufacturing, government and service industries – are experiencing severe and prolonged shortages of "people power."

It's not just the quantity of workers that is a concern – the quality of our workforce is just as important. From the megaproject oil sands operations to small businesses in our communities, high-quality work starts with well-trained, qualified employees who know how to do the job right, and do the job safely.

To help address this issue, Suncor is supporting innovative apprenticeship programs and investing in skills training initiatives at technical institutes and colleges. We're also working to address the issue of regional labour bottlenecks in Fort McMurray. For example, we plan to have 35% to 40% of fabrication for our third oil sands upgrader and supporting infrastructure completed off site and we are 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 to spread the economic benefits of our business more widely.

Growing Responsibly

Building and broadening economic benefits is part of Suncor's overall vision of sustainability – a vision that recognizes that a strong economy, a healthy environment and community well-being are complementary and interdependent. We believe our integrated performance on these measures is a solid foundation for our future growth and profitability, helping us reduce risks, identify new opportunities and deliver strategies that are broad in scope and long-term in vision.

While Suncor is justifiably proud of our record of delivering value to shareholders – an average annual return of more than 30% since we became publicly traded in 1992 – we are also very proud of our record of delivering for our communities and our shared environment.

In the past five years alone, Suncor has contributed more than $33 million to community and charitable initiatives, including a record $9 million in 2005. Over the same period, we have improved the diversity of our workforce from frontline employees to management and significantly reduced lost-time injuries on our work sites.

We've also continued to make progress on our goal to be a leader in environmentally responsible energy development. We are on track to more than triple our generation of zero-emission wind power in the next two years. At the same time, we are aggressively pursuing reductions in the intensity of air emissions and water use at all of our operations. Our regulatory application for a third oil sands upgrader, for example, anticipates no net increase in water use despite a doubling of our production.

Our "triple bottom line" performance focus is an important part of Suncor's strategy and corporate culture as we work with governments, communities, and social and environmental advocates to earn their support for our growth plans. I encourage shareholders to review our progress in Suncor's Report on Sustainability*, which is just one part of a governance philosophy that aims to meet shareholders' expectations of transparent disclosure, high standards of corporate conduct and, of course, strong management of your company. Suncor's Board of Directors, who oversee all aspects of governance, have been instrumental in stewarding the long-term interests of shareholders and challenging management to exceed expectations – and I would like to recognize them for their guidance and support.

I would also like to recognize the support and outstanding work of Suncor's 5,000 employees. From industry veterans to newly qualified tradespeople and professionals, Suncor's employees reflect very much the balance of industry-leading experience and tremendous future potential that characterize this company. The challenges inherent in all that we will build on the journey to half a million barrels per day will be supported by all that we have built so far. I look forward to the journey and, on behalf of Suncor's employees, management and your Board of Directors, I thank you for your support.

Rick George
president and chief executive officer

* Available online at www.suncor.com or by calling 1-800-558-9071.

LEADERSHIP TEAM

(left to right) Terry Hopwood, Dave Byler, Ken Alley, Sue Lee, Rick George, Steve Williams, Mike Ashar, Tom Ryley, Jay Thornton, Kevin Nabholz

Delivering shareholder value and building on a proven strategy requires a proven leadership team. A vast breadth of experience and expertise combined with a common focus on innovation, integrity and accountability are what defines the team that reports to Rick George, Suncor's president and chief executive officer.

Steve Williams, executive vice president, Oil Sands, brings to Suncor international energy industry experience in refinery management, strategy development and organizational performance improvement. Steve's role is to keep 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 a 27-year Suncor veteran who has held senior positions in finance, information technology and human resources. Dave is charged with meeting our strategic goals by increasing natural gas production to offset growing internal demand. Dave also leads Suncor's work on greenhouse gas mitigation strategies, including our renewable energy business.

Tom Ryley, executive vice president, Energy Marketing and Refining – Canada, is a seasoned marketing strategist and leader of Suncor's refining and marketing business in one of the most competitive markets in North America. Tom is also responsible for optimizing the profitability of our growing crude oil and natural gas production in markets throughout North America.

Mike Ashar, executive vice president, Refining and Marketing – U.S.A., leads Suncor's U.S. refining and marketing operations and is responsible for advancing our downstream integration and Suncor's corporate strategy in the world's largest crude oil market. With leadership experience in our oil sands business and refining and marketing operations, Mike knows our products and our markets – and how to connect the two.

In a business that is defined by huge capital investment and one of the world's most complex engineering, procurement and construction environments, **Kevin Nabholz,** executive vice president, Major Projects, is charged with bringing in growth projects on time and on budget.

Sue Lee, senior vice president, Human Resources and Communications, is responsible for strategies to recruit and retain the people who put our growth plans into action. Sue is also responsible for strategies to engage community and government stakeholders and advocacy groups, ensuring we maintain broad support for our current operations and growth plans.

A growing business means an increasingly complex regulatory environment and critical business-to-business negotiations. **Terry Hopwood,** senior vice president and general counsel, is Suncor's lead negotiator and chief legal officer.

Suncor's integrated strategy requires that every part of the business works together to support growth while keeping costs in check. **Jay Thornton,** senior vice president, Business Integration, is responsible for delivering cost-efficient services and effective cross-company integration of processes and technology.

With annual capital investment of $3.5 billion, **Ken Alley,** senior vice president and chief financial officer, is charged with maintaining a strong balance sheet and solid financial base. Ken leads Suncor's strategies on debt, hedging, tax and insurance. Ken is also responsible for leading our strategy on environmental issues.

OUR SCORECARD

2005: What we promised and what we delivered

Complete fire recovery and planned maintenance at oil sands – return to full production in the third quarter. Recovery and planned maintenance work was completed on schedule, with the plant running at full capacity by the end of September.

Increase natural gas production volumes to 205 to 210 million cubic feet (mmcf) per day. At 190 mmcf per day, natural gas production fell short of target due to unplanned maintenance and weather-related delays in drilling and tie-ins.

Build for future oil sands growth. Expansion of our oil sands facilities to 260,000 barrels per day (bpd) was completed on schedule and on budget. In March, we filed a regulatory application for plans to take daily production to more than 500,000 bpd in 2010 to 2012.

Advance downstream integration plans. Suncor began in 2005 to integrate newly acquired refining assets into what is now the largest refining operation in the U.S. Rocky Mountain region. Construction activity reached peak levels at the Sarnia and Commerce City refineries on modifications to allow both facilities to produce low-sulphur fuels and integrate larger volumes of oil sands sour crude production.

Reduce lost-time injury frequencies. We fell short of targets on this key safety measure, with lost-time injury frequency remaining virtually unchanged over 2004.

Focus on enterprise-wide efficiency. To more seamlessly integrate operations and support growth plans, Suncor completed the first stage of a company-wide upgrade to many business processes and systems.

Maintain a strong balance sheet. While net debt increased to $2.9 billion due to higher capital spending and expenses associated with fire recovery, we ended the year with a debt to cash flow ratio of 1.2, up only slightly from a ratio of 1.1 in 2004.

Continue to pursue energy efficiencies, greenhouse gas offsets and new, renewable energy projects. In addition to advancing research into carbon capture, Suncor began construction on an ethanol plant in Ontario and a wind power project in Alberta.

2006: Our targets and how we'll get there

Increase annual oil sands production to 260,000 bpd at average cash operating costs of $16 to $16.75 per barrel. With a newly expanded plant, we are targeting record oil sands production in 2006. Steady and reliable production will help us manage cash operating costs, although sustained high natural gas prices may impact targets.

Advance plans for increased bitumen supply. We expect to achieve full production capacity from Firebag stage one and a steady ramp-up from Firebag stage two. In our mining operations, we expect to substantially complete engineering for the Steepbank mine extension and new extraction facilities.

Advance plans for increased upgrader capacity. Continuing on-site construction work is expected to support plans to take Suncor to 350,000 bpd in 2008. A regulatory hearing regarding our plans for increasing production to more than 500,000 bpd is also anticipated in 2006.

Increase natural gas production to an average 205 to 210 mmcf per day. We will continue to focus on high-impact, deep gas prospects and in 2006, expect to increase natural gas production by 8% to 10%.

Reduce lost-time injury frequency. Suncor will introduce new business processes and tools aimed at improving our ability to identify and manage risks and prevent operational incidents.

Focus on enterprise-wide efficiency. To more seamlessly integrate operations and improve efficiency and productivity, Suncor expects to complete a company-wide centralization of support services and an associated upgrade to many business processes and systems.

Advance downstream integration. In 2006, major maintenance shutdowns at our refining operations are planned to improve operational reliability and tie-in sour crude processing facilities.

Maintain a strong balance sheet. Tight management of debt and strategic hedging of portions of production will be key to the balance sheet as we plan capital investment of $3.5 billion in 2006.

Continue to pursue energy efficiencies, greenhouse gas offsets and new, renewable energy projects. Suncor expects to commission a plant to supply ethanol for lower emission, blended fuels in the Ontario market. Our third wind power project at Chin Chute, Alberta is expected to be commissioned, while construction is expected to begin on the Ripley Wind Power Project in Ontario.

Vast Potential

As the first company to develop the oil sands, Suncor has secured some of the largest lease holdings in the Athabasca region.

Independent reserve evaluators have estimated that our leases hold bitumen reserves and resources sufficient to produce a potential 14 billion barrels of refinery-ready oil. But unlike conventional oil development, relatively little exploration is required to establish the location, size and quality of our reserves.

In-situ

Less than one-fifth of the oil sands resource is mineable. Most must be recovered by in-situ methods – drilling into the reservoir and injecting steam to heat the bitumen and move it to the surface.

For this reason, Suncor has built on our position as a leading 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 growth strategy. Total production from Firebag stage one had surpassed 10 million barrels of bitumen by the end of 2005. Those volumes are expected to continue to increase as stage one ramps up to full capacity and stage two, completed in December 2005, adds new production.

While the costs of producing in-situ bitumen feed are currently higher than costs for conventional mining, Suncor is investigating new technologies that hold the promise of closing the gap. Pilot projects using solvent injection to reduce the viscosity of the bitumen, and underground mechanical pumps are two technologies currently being investigated. If they prove effective, these new technologies hold the promise of reducing natural gas energy requirements – the biggest cost factor in our SAGD operations.

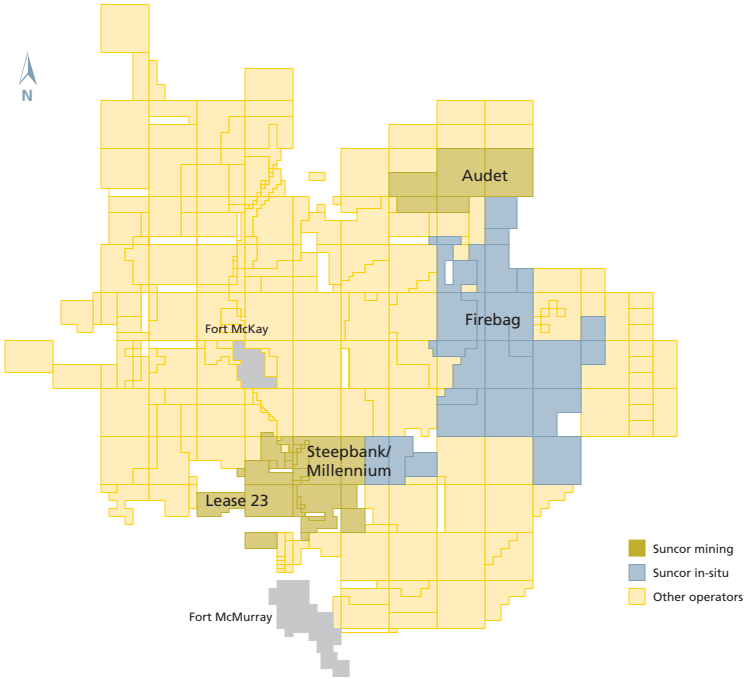
Mining

While in-situ development is a key part of our operations and a promising option for future growth, mining remains the bedrock of our flexible feedstock plans. Suncor is a leader in oil sands mining, with four decades of experience and more than one billion barrels of bitumen recovered from three mines. As we head towards our half million barrel per day target, we are planning to expand our mining options by delineating the oil sands resources in two new areas: Lease 23, immediately west of our current operations and Audet, a potential mining lease north of our Firebag operations.

While we aim for expansion, we are also aiming for improvement. Technological advancements – from mobile crushers to new extraction methods – are under development with the goal of increasing mine efficiency and reducing costs.

Third-Party Agreements

To provide greater flexibility and improved reliability of bitumen feed, Suncor supplements our own mining and in-situ operations with third party supply and processing agreements. We have several agreements in place and plan to continue to pursue supply opportunities as third party bitumen in the Athabasca region continues to expand more quickly than announced upgrading capacity.

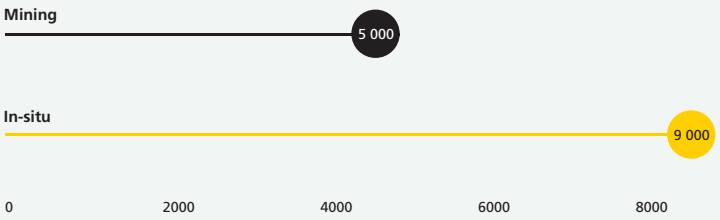


What does > 500,000 bpd look like?*

Suncor's resource supply plans include:

- Three to six stages of in-situ development on our Firebag lease. The number and configuration of stages will vary depending on cost and technology considerations.
- Accelerated mining from our existing Millennium mine and, beginning in 2010, from the planned North Steepbank mine extension.
- Possible new mining operations on Lease 23 and the Audet lease.
- Third party supply agreements that are expected to provide supplemental bitumen production.

> 14 billion barrels of resources



Resources – Barrels of Synthetic Crude Oil (millions)

"Remaining recoverable resources" is the total of reserves and contingent resources. The term "resources" used herein refers to a best estimate of remaining recoverable resources, being 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 our independent reserve evaluators' best estimate of resources that 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 commercial development plan that includes a firm intent to develop within a reasonable timeframe, and due to higher uncertainty as a result of lower core-hole drilling density. For a description of constant cost and pricing assumptions used to evaluate the proved and probable reserves included in our resource estimate, see page 34. 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 our reserves under U.S. reporting requirements, see pages 34 to 36.

* Plans are subject to Board of Directors and regulatory approval.

Real Value

While abundant bitumen supplies are the foundation of the oil sands industry, it's upgrading that delivers the real value. Suncor processes raw resources into the high-quality energy products the market demands. Since producing the world's first barrel of oil sands crude, Suncor has expanded production capacity significantly – an average of 20% per year in the last five years alone.

Expansion Plans

In October 2005, we announced the successful commissioning of a $450 million expansion to our oil sands upgrading operations, which increased production capacity to 260,000 barrels per day (bpd).

Our next major expansion phase includes adding a third set of cokers to Upgrader 2. Major vessel fabrication for this expansion is complete and we're on target for our goal of production capacity of 350,000 bpd in 2008.

Beyond 2008, plans are coming together to expand daily production even further to half a million barrels. In March 2005, Suncor filed a regulatory application to build a third oil sands upgrader. The proposed facility will have twice the capacity of either of our current two upgraders, with cokers that will be among the largest in the world. A regulatory decision on Suncor's application is expected in 2007. We will use this time to move preliminary engineering forward, confirm our cost estimates and seek approval from Suncor's Board of Directors.

As we take our expansion plans from the drawing board to steel and pipe on the ground, managing capital costs will be critical. Suncor's own engineering, procurement and construction experts will lead the planning and execution of our growth plans every step of the way.

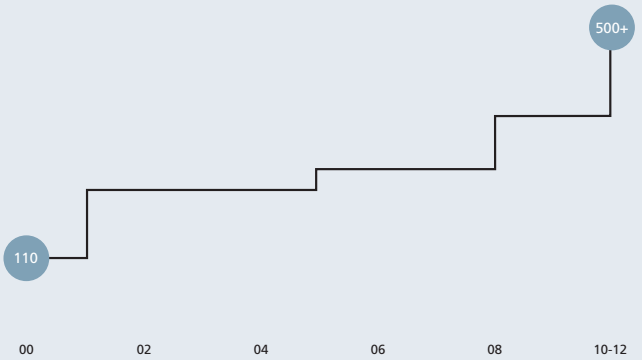
Natural Gas

While oil sands operations are the centrepiece of our strategy and growth plans, Suncor's natural gas business is also key to creating value in our integrated operations. Producing our own natural gas provides a price hedge against purchases for internal consumption at our oil sands and refining operations. In 2005, we produced 190 million cubic feet per day of natural gas – enough to sell a net surplus into a strong North American gas market. We are 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.

What does > 500,000 bpd look like?*

Suncor's production plans include:

- A third upgrader that is central to our oil sands growth plans, providing increased production and greater operational reliability. The upgrader is planned to include three coker pairs; gas oil, diesel and naphtha hydrotreaters; hydrogen production; utilities; and support infrastructure.
- Canada's first stand-alone petroleum coke gasifier. If plans go ahead, this clean-burning technology would process petroleum coke, a byproduct of the proposed upgrader, into synthetic fuel gas and hydrogen, reducing Suncor's reliance on natural gas.



Year-end Production Capacity (thousands of barrels per day)

2006 and subsequent years represent targets.

> increasing production capacity

* Plans are subject to Board of Directors and regulatory approval.

Big Opportunity

Suncor's refining and marketing strategy is aimed 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. Suncor is connected to that market through a variety of transportation and sales agreements and our own refineries and retail networks in Ontario and Colorado.

Energy Marketing

With a range 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. Every day, our energy marketing team sells hundreds of thousands of barrels of crude through a portfolio of proprietary and managed pipeline capacity, allowing flexibility and ease of response to our customers' diverse needs and changing market conditions.

Refining

While we work to expand upstream production, we're putting technology to work right now to build the downstream operations that will add value to our products. Major upgrades to our Sarnia and Commerce City refineries are designed to allow us to meet low sulphur fuel regulations in Canada and the United States, while also enabling both refineries to accommodate higher volumes of oil sands crude blends.

When complete in 2007, modifications to the 70,000 barrel per day (bpd) Sarnia refinery are expected to allow the facility to process approximately 40,000 bpd of sour crude blends, finishing the work of upgrading oil sands products at a lower capital cost than building the facilities in northern Alberta. At our Commerce City refinery, modifications scheduled for completion in 2006 should allow the processing of 10,000 to 15,000 bpd of oil sands blends. Along with the 2005 acquisition of a neighbouring facility that expands refining capacity to 90,000 bpd, these modifications are key to our expanding presence in the U.S. Rocky Mountain market.

Retail

Suncor operates retail stations and supplies products to a broader retail network through joint venture operations and long-term supply contracts. Operating under the Sunoco brand in Ontario and Phillips 66® brand in Colorado, our retail service networks provide an opportunity to capture further value from our refined products. Retail sites in both networks are undergoing renovations and improvements to associated convenience stores to help maintain and build market share in this highly competitive business.

Renewable Energy

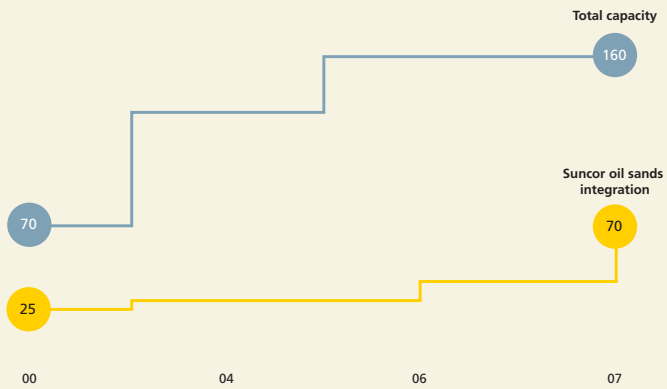
While we work to responsibly develop hydrocarbon resources, Suncor is also investing in clean, renewable energy sources. By 2008, Suncor plans to have four projects in operation with a total capacity of 147 megawatts of renewable energy as an alternative to hydrocarbon-fuelled generation. These projects are expected to offset the equivalent of approximately 270,000 tonnes of carbon dioxide annually.

In Ontario, Suncor expects to complete construction in 2006 on a plant that will supply ethanol – a renewable energy source – for lower-emission blended fuels.

What does > 500,000 bpd look like?*

Suncor's marketing plans include:

- A continuing "portfolio" approach to our products, with a range of refinery-ready sweet and sour blended crudes and diesel fuel.
- Pursuing further opportunities to integrate our products into the markets through long-term contracts.
- Possible joint ventures or the acquisition of additional refining assets.
- Potential modification of our Commerce City refinery to handle up to an additional 30,000 bpd of oil sands crude blends.



Suncor Year-end Refining Throughput (thousands of barrels per day)

2006 and subsequent years represent targets.

> integrating production

* Plans are subject to Board of Directors and regulatory approval.

BEYOND HALF A MILLION BARRELS PER DAY

In the past decade Suncor has earned a reputation for exceeding expectations. Our timetable for production growth has been met and our commitment to environmental stewardship and social responsibility continues to reflect a belief in leadership by example.

We have the support of the most experienced employees in the oil sands business and a proven track record that has built shareholder confidence in our future ability to generate value.

Our plans to reach half a million barrels per day are progressing and, although there are no guarantees about future outcomes, the reputation we have for delivering on our promises makes us confident our plans will be achieved.

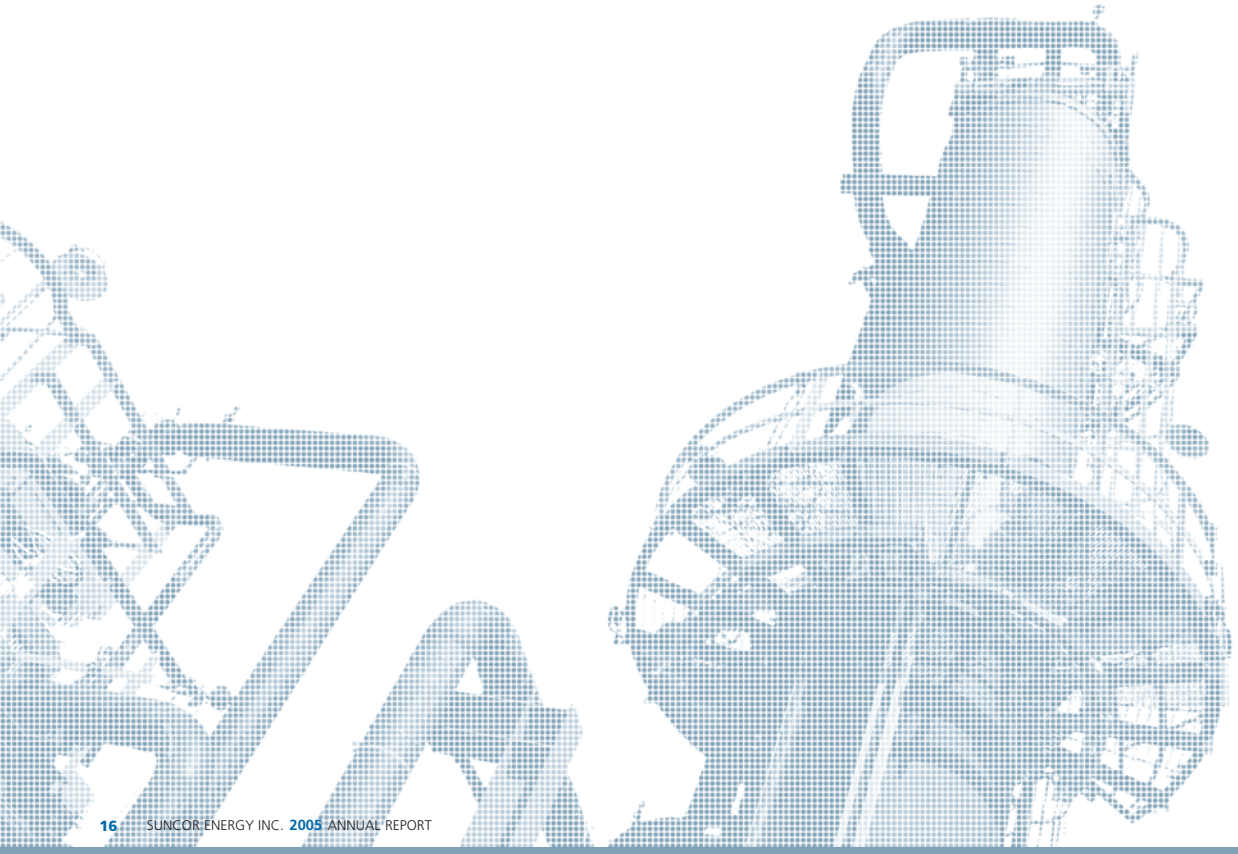
What's next? The blueprints for Suncor's operations beyond 2012 have not been drawn; but we do believe that growth won't stop there.

Our integrated growth strategy provides a good indicator of what's to come once our half million barrels per day target has been achieved:

- Expanded resource development
- Staged production growth
- Extended market reach

Because we pride ourselves in exceeding expectations and delivering on our commitment for responsible resource development, we won't rush to put out targets that are based on guesswork. Instead, we'll take the time to apply what we've learned from our past performance to ensure our future plans will meet shareholder expectations: growth projects delivered on time and on budget; reliable, safe and well-managed businesses that generate double-digit returns; and a triple bottom line focus that generates value for shareholders while also striving for broad social benefits and a reduced impact on our environment.

We've only just begun.



MANAGEMENT'S DISCUSSION AND ANALYSIS

March 1, 2006

This Management's Discussion and Analysis (MD&A) contains forward-looking statements. These statements are based on certain estimates and assumptions and involve risks and uncertainties. Actual results may differ materially. See page 58 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 56.

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

Base operations refers to Oil Sands mining and upgrading operations.

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

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

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

Additional information about Suncor filed with Canadian securities commissions and the United States Securities and Exchange Commission (SEC), including periodic quarterly and annual reports and the Annual Information Form (AIF) filed with the SEC under cover of Form 40-F, is available on-line at www.sedar.com, www.sec.gov and our website www.suncor.com.

In order to provide shareholders with full disclosure relating to potential future capital expenditures, we have provided cost estimates for projects that, in many cases, are still in the early stages of development. These costs are preliminary estimates only. The actual amounts are expected to differ and these differences may be material. For a further discussion of our significant capital projects and the range of cost estimates associated with an "on-budget" project, refer to note 1 under "Significant Capital Project Update" on page 26.

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.
- **Energy Marketing and Refining – Canada** (EM&R) operates a 70,000 barrel per day (bpd) capacity refinery in Sarnia, Ontario and 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 those business segments.
- **Refining and Marketing – U.S.A.** (R&M) operates 90,000 bpd of refining capacity in Commerce City, Colorado as well as related pipeline assets. R&M markets refined petroleum products to customers throughout Colorado.

Suncor's strategic priorities are:

Operational:

- Developing our oil sands resource base through mining and in-situ technology and supplementing Suncor bitumen production with third party supply.
- Expanding Oil Sands mine, in-situ, extraction and upgrading facilities to increase crude oil production.
- 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 earn continued stakeholder support for our ongoing operations and growth plans.
- Maintaining a strong focus on worker, contractor and community safety.
- Pursuing new technology applications to increase production and reduce costs and environmental impacts.

Financial:

- Controlling costs through a strong focus on operational excellence, economies of scale and improved 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 controlling debt and closely managing capital cost outlays.
- Targeting opportunities that have the potential to support a minimum 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.

2005 Overview

- In September we completed rebuilding portions of our Oil Sands plant that were damaged by fire on January 4, 2005. The recovery and planned maintenance work was completed on schedule and the plant was running at full capacity by the end of September.
- In October, we successfully commissioned an expansion of our Oil Sands facilities that increased production capacity to 260,000 bpd from the previous capacity of 225,000 bpd. The project was completed on schedule and on budget. Work to further expand Oil Sands production capacity to 350,000 bpd in 2008 also progressed during the year and is on schedule and on budget.
- Construction of the second stage of our Firebag in-situ operation was completed on schedule and on budget. Commercial operations are expected to commence in the first quarter of 2006.
- In 2005, we produced 190 million cubic feet per day (mmcf/d) of natural gas from our conventional upstream operations compared to 200 mmcf/d in 2004. The decline was primarily due to weather related drilling delays and unplanned maintenance. Production remained in excess of volumes purchased for use in our Oil Sands and downstream operations.
- On May 31, 2005, we acquired the Colorado Refining Company from Valero Energy Corp., which included a 30,000 bpd refinery located adjacent to our existing refinery in Commerce City, Colorado. This combined operation is now the largest refining complex in the U.S. Rocky Mountain region.
- Construction continued on modifications to our Sarnia and Commerce City refineries to meet low-sulphur fuels regulations that will take effect in 2006.
- Maintaining a strong balance sheet remains a priority. Despite the impact of costs associated with the fire recovery, and an increase in capital spending to $2.8 billion (excluding the cost of the fire rebuild and capitalized interest), net debt (including cash and cash equivalents) at December 31, 2005 was $2.9 billion (1.2 times cash flow from operations), compared to $2.2 billion (1.1 times cash flow from operations) at December 31, 2004.
- Our company-wide ROCE (excluding major projects in progress) was 20.9% compared to 19% in 2004.

SELECTED FINANCIAL INFORMATION

Annual Financial Data

Year ended December 31 ($ millions except per share data)	**2005**	2004	2003
Revenues	**11 086**	8 665	6 611
Net earnings	**1 245**	1 088	1 087
Total assets	**15 351**	11 841	10 540
Long-term debt	**3 007**	2 217	2 934
Dividends on common shares	**102**	97	81
Net earnings attributable to common shareholders per share – basic	**2.73**	2.40	2.42
Net earnings attributable to common shareholders per share – diluted	**2.67**	2.36	2.26
Cash dividends per share	**0.24**	0.23	0.1925

Outstanding Share Data

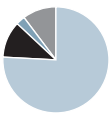
As at December 31, 2005 (thousands)	
Number of common shares	457 665
Number of common share options	19 203
Number of common share options – exercisable	9 361

Quarterly Financial Data

	2005 Quarter ended				2004 Quarter ended			
($ millions except per share)	**Dec. 31**	**Sept. 30**	**June 30**	**Mar. 31**	Dec. 31	Sept. 30	June 30	Mar. 31
Revenues	**3 503**	**3 142**	**2 380**	**2 061**	2 321	2 326	2 212	1 806
Net earnings	**694**	**341**	**112**	**98**	333	337	202	216
Net earnings attributable to common shareholders per share								
Basic	**1.52**	**0.75**	**0.24**	**0.22**	0.73	0.74	0.45	0.48
Diluted	**1.48**	**0.73**	**0.24**	**0.21**	0.72	0.73	0.43	0.46

Net Earnings[1]

Year ended December 31,
($ millions)



	05	04	03
Oil Sands	**1 073**	994	887
Natural Gas	**155**	115	120
Energy Marketing and Refining – Canada	**41**	80	53
Refining and Marketing – U.S.A.[3]	**142**	34	18

Cash Flow from Operations[1]

Year ended December 31,
($ millions)

	05	04	03
Oil Sands	**1 895**	1 752	1 803
Natural Gas	**412**	319	298
Energy Marketing and Refining – Canada	**152**	188	164
Refining and Marketing – U.S.A.[3]	**247**	59	34

Capital Employed[1] [2]

Year ended December 31,
($ millions)

	05	04	03
Oil Sands	**4 633**	4 169	4 050
Natural Gas	**563**	448	400
Energy Marketing and Refining – Canada	**486**	512	551
Refining and Marketing – U.S.A.[3]	**327**	232	270

(1) Excludes Corporate and Eliminations segment.
(2) Excludes major projects in progress.
(3) Refining and Marketing – U.S.A. 2003 data reflects five months of operations since acquisition on August 1, 2003. Data for 2005 includes results of the former Colorado Refining Company, acquired May 31, 2005.

Fluctuations in quarterly net earnings for 2005 and 2004 were due to a number of factors:

- The January 2005 fire at Oil Sands significantly reduced crude oil production to approximately 122,000 bpd for the first nine months of 2005.
- U.S. dollar denominated crude oil and natural gas prices were higher on average in 2005 compared to 2004. WTI averaged US$56.55 per barrel (bbl) in 2005 compared to US$41.40/bbl in 2004, and Henry Hub natural gas prices averaged US$8.55/mcf in 2005, compared to US$6.20/mcf in 2004.
- Cash operating costs fluctuated due to variations in Oil Sands production levels, the timing and amount of maintenance activities, and the price and volume of natural gas used for energy in Oil Sands operations.
- 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 fluctuations were reflected in higher demand for vehicle fuels and asphalt in summer and heating fuels in winter. Prices were also affected by decreased market supply as a result of hurricane activity in the Gulf of Mexico during the summer of 2005.
- Realized commodity prices were unfavourably impacted in 2005 and 2004 by increases in the Canadian dollar compared to the U.S. dollar, which reduced the Canadian dollar revenues earned. The stronger Canadian dollar also resulted in net foreign exchange gains on U.S. dollar denominated debt in 2005 and 2004. The higher appreciation of the Canadian dollar compared to the U.S. dollar in 2004 over 2005 resulted in higher foreign exchange gains in 2004 compared to 2005.
- A 1% reduction in the Province of Alberta's corporate tax rates in the first quarter of 2004 increased 2004 net earnings by $53 million.
- The timing and amount of insurance receipts related to the fire at Oil Sands in January 2005.

Consolidated Financial Analysis

This analysis provides an overview of our consolidated financial results for 2005 compared to 2004. For a detailed analysis, see the various business segment analyses.

Net Earnings

Our net earnings were $1.245 billion in 2005, compared with $1.088 billion in 2004 (2003 – $1.087 billion). The increase was primarily due to higher U.S. dollar benchmark crude oil and natural gas prices, the receipt of insurance payments related to the January 2005 fire at our oil sands facility and lower hedging losses. These positive impacts were partially offset by lower Oil Sands and Natural Gas production, higher maintenance expenses, higher energy costs in our Oil Sands and downstream operations, and the impact of a stronger Canadian dollar.

Net Earnings Components [1]

Year ended December 31 ($ millions, after-tax)	**2005**	2004	2003
Net earnings before the following items:	**1 114**	1 242	1 021
Firebag in-situ start-up costs [2]	**(4)**	(14)	—
Oil Sands fire accrued insurance proceeds [2]	**360**	—	—
Oil Sands Alberta Crown royalties	**(256)**	(261)	(21)
Impact of income tax rate reductions on opening net future income tax liabilities	**—**	53	(89)
Unrealized foreign exchange gains on U.S. dollar denominated long-term debt	**31**	68	176
Net earnings as reported	**1 245**	1 088	1 087

(1) This table highlights some of the factors impacting Suncor's after-tax net earnings. For comparability purposes, readers should rely on the reported net earnings that are prepared and presented in the consolidated financial statements and notes in accordance with Canadian GAAP.
(2) Before deduction of Alberta Crown royalties.

Industry Indicators

(Average for the year unless otherwise noted)	**2005**	2004	2003
West Texas Intermediate (WTI) crude oil US$/barrel at Cushing	**56.55**	41.40	31.05
Canadian 0.3% par crude oil Cdn$/barrel at Edmonton	**69.00**	52.55	43.55
Light/heavy crude oil differential US$/barrel WTI at Cushing less Lloydminster Blend at Hardisty	**20.90**	13.55	8.65
Natural gas US$/thousand cubic feet (mcf) at Henry Hub	**8.55**	6.20	5.45
Natural gas (Alberta spot) Cdn$/mcf at AECO	**8.50**	6.80	6.70
New York Harbour 3-2-1 crack US$/barrel (1)	**9.50**	6.90	5.30
Ontario refined product demand percentage change over prior year (2)	**0.2**	4.3	2.5
Colorado light product demand percentage change over prior year (3)	**3.3**	7.2	(2.2)
Exchange rate: Cdn$/US$	**0.83**	0.77	0.72

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

(2) Figures for 2003 and 2004 are based on published government data. The figure for 2005 is an internal estimate based on preliminary government data.

(3) Figures for 2003 and 2004 are based on public reporting by state and government agencies. The 2005 figure is based on consensus estimates by third party consultants.

Revenues were $11.1 billion in 2005, compared with $8.7 billion in 2004 (2003 – $6.6 billion). The increase was primarily due to the following:

- Average commodity prices were higher in 2005 than in 2004. A 37% increase in average U.S. dollar WTI benchmark prices increased the selling price of Oil Sands crude oil production. Offsetting this increase, average light/heavy crude oil differentials compared to the WTI benchmark index widened by approximately 54%. As a result, the net price we received on certain sour crude oil and bitumen sales did not increase by as much as the increase in WTI.
- Refined product wholesale and retail prices in both EM&R and R&M were higher due to higher crude oil and refined product prices. In addition, a 47% increase in refined product sales volumes in R&M due to the acquisition of the Colorado Refining Company in the second quarter of 2005 had a positive impact on revenue.
- Lower strategic crude oil hedging losses increased revenues by $85 million. During 2005, we sold a portion of our crude oil production at fixed prices that were lower than prevailing market prices. During 2005 we sold 36,000 bpd at a fixed price of US$23/bbl compared to 79,000 bpd in 2004 at a fixed price range of US$21/bbl to US$24/bbl. Pretax hedging losses in 2005 were $535 million compared to $620 million in 2004.
- The recognition of $572 million pretax in net insurance proceeds related to the January 2005 fire at our Oil Sands operations.

Partially offsetting these increases were the following:

- An 8% increase in the average Cdn$/US$ exchange rate resulted in lower realizations on our crude oil sales basket and our natural gas sales. Because crude oil and natural gas are 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.
- In 2005, Oil Sands sales volumes averaged 165,300 bpd, compared with 226,300 bpd in 2004 (2003 – 218,300 bpd). Decreased crude oil production as a result of the fire, and an inventory build in the fourth quarter resulted in lower sales volumes. Oil Sands sales in 2005 included 16,600 bpd of bitumen from Firebag in-situ operations (2004 – 8,400 bpd; 2003 – 6,400 bpd).
- Natural gas production averaged 190 mmcf/d in 2005 compared to 200 mmcf/d in 2004. Lower production was the result of weather related drilling delays that impacted the western Canadian industry, as well as unplanned maintenance.

Overall, higher prices, net of the impact of the higher Cdn$/US$ exchange rate, increased total revenues by approximately $2.2 billion and lower hedging losses increased revenues by approximately $85 million. These impacts were partially offset by lower sales volumes that decreased revenues by approximately $800 million.

Purchases of crude oil and crude oil products were $4.2 billion in 2005 compared with $2.9 billion in 2004 (2003 – $1.7 billion). The increase was primarily due to the following:

- Higher benchmark crude oil prices. This factor had the largest impact on product purchases for EM&R and R&M as WTI increased 37% over the prior year.

- Increased purchases of crude oil feedstock to utilize the additional refining capacity acquired by R&M in the second quarter of 2005. The acquisition increased our Commerce City refining capacity from 60,000 bpd to 90,000 bpd.
- Purchased volumes of crude oil and refined products decreased in EM&R. In 2004, larger amounts of refined products were purchased to meet customer demand during the maintenance shutdown that occurred in the second quarter.
- In 2004, the repurchase of crude oil originally sold to a Variable Interest Entity (VIE) in 1999 increased purchases at Oil Sands by approximately $55 million. There was no similar transaction in 2005.

Operating, selling and general expenses were $2.1 billion in 2005 compared with $1.8 billion in 2004 (2003 – $1.5 billion). The primary reasons for the increase were:

- Higher operating expenses primarily due to higher energy costs in our Oil Sands and downstream operations.
- Increased maintenance related costs at Oil Sands, primarily to ensure reliability of the upgrader that was not damaged by the fire.
- Higher stock-based compensation expenses caused by increases in our share price.
- Incremental operating costs associated with the acquisition of the Colorado Refining Company in 2005.

Transportation and other expenses were $152 million in 2005 compared to $132 million in 2004 (2003 – $135 million). In 2004, mark-to-market gains on inventory-related derivatives of $13 million in Oil Sands reduced transportation and other costs. Despite decreased production in our Oil Sands operations, transportation costs, excluding the mark-to-market gain from 2004, have remained relatively constant due to the "ship-or-pay" nature of the contracts with our shippers. Consistent with 2004, Oil Sands pipeline tolls continued to be reduced by initial shipper toll adjustments. These toll reductions are currently expected to continue until at least 2007.

Depreciation, depletion and amortization (DD&A) was $720 million in 2005, consistent with 2004 (2003 – $622 million). DD&A at Oil Sands decreased by $23 million due to lower overburden amortization as a result of lower production, partially offset by higher maintenance shutdown and catalyst amortization, and depletion incurred in in-situ operations. NG DD&A increased by $15 million, reflecting an increased proved asset base and higher amortization related to unproven lands.

Royalty expenses were $555 million in 2005 compared with $531 million in 2004 (2003 – $139 million). The increase in 2005 was primarily related to increased natural gas royalties due to higher price realizations, partially offset by lower natural gas volumes. For a discussion of Oil Sands Crown royalties, see page 27.

Taxes other than income taxes were $529 million in 2005 compared to $540 million in 2004 (2003 – $466 million). The decrease was primarily due to lower sales volumes subject to fuel excise taxes (FET) in our Oil Sands and EM&R operations, partially offset by higher sales volumes subject to FET in our R&M operations.

Financing income was $15 million in 2005 compared with expenses of $24 million in 2004 (2003 – income of $74 million). The decrease in expenses was primarily due to higher amounts of capitalized interest, lower effective interest rates and the effects of foreign exchange on U.S. dollar operating accounts, partially offset by a $45 million decrease in foreign exchange gains on our U.S. dollar denominated long-term debt. Interest expense, net of capitalized interest, was $32 million in 2005 compared to $95 million in 2004. Interest expense, net of capitalized interest, decreased primarily due to more capital projects meeting the criteria for interest capitalization.

Income tax expense was $742 million in 2005 (37% effective tax rate), compared to $530 million in 2004 (33% effective tax rate) (2003 – $718 million – 40% effective tax rate). Income tax expense in both 2004 and 2003 included the effects of adjustments to opening future income tax balances due to changes in tax rates that reduced tax expense by $53 million in 2004 and increased tax expense by $89 million in 2003. Excluding these adjustments, income tax expense in 2004 was $583 million (36% effective tax rate) and $629 million in 2003 (35% effective tax rate).

Corporate Expenses

After-tax corporate expenses were $166 million in 2005 compared to $135 million in 2004 (2003 – $9 million). The increase was due to higher stock-based compensation expenses and higher insurance related costs, partially offset by lower financing costs as discussed previously. Corporate had a net cash deficiency of $122 million in 2005, compared with $343 million in 2004 (2003 – $280 million). The reduced deficiency was primarily due to changes in working capital.

Consolidated Cash Flow from Operations

Cash flow from operations was $2.476 billion in 2005 compared to $2.013 billion in 2004 (2003 – $2.040 billion). The increase in cash flow from operations was primarily due to the same factors that impacted earnings, with the exception of foreign exchange gains on our U.S. dollar denominated long-term debt and future income taxes, both of which are non-cash items.

Dividends

Total dividends paid during 2005 were $0.24 per share, compared with $0.23 per share in 2004. 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 2004, the Board approved an increase in the quarterly dividend to $0.06 per share, from $0.05 per share.

Oil Sands Fire

On January 4, 2005, a fire at our Oil Sands operations damaged Upgrader 2, reducing production from base operations to approximately 122,000 bpd for the first nine months of the year. Repairs and scheduled maintenance were completed in September 2005, at which time operations returned to full production capacity.

We expect our property loss and business interruption (BI) insurance policies to significantly mitigate the financial impact of the fire. During 2005, we received $115 million (US$95 million) from our property loss policy and $594 million (US$500 million) in proceeds from our BI insurance policies, including $175 million (US$150 million) received in January and February 2006. The company is currently negotiating a final settlement with its business interruption insurers. Any subsequent proceeds will be recorded when unconditionally received or receivable.

For royalty purposes, BI proceeds are treated in the same manner as the revenues they replace and, accordingly, attract Alberta Crown royalties. For further discussion about Oil Sands Crown royalties, see page 27.

In the fourth quarter of 2005, we renewed our property and BI insurance programs. All of our policy limits and deductibles remain unchanged except as noted. We carry primary and excess property loss and BI coverage with a combined limit up to US$1.150 billion, net of deductible amounts. The primary property loss policy of US$250 million has a deductible of US$10 million per incident and the primary BI policy of US$200 million has a deductible per incident of the greater of US$50 million gross earnings lost (as defined in the insurance policy) or 30 days from the incident.

The excess coverage of US$700 million can be used for either property loss or BI coverage for our Oil Sands operations. For BI purposes, this excess coverage is available commencing on the later of full utilization of the primary BI coverage or 90 days from the date of the incident. Effective January 1, 2006, the excess coverage has a ceiling of US$40/bbl WTI for purposes of determining the amount of BI losses.

Liquidity and Capital Resources

At December 31, 2005, 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 levels, downstream margins and Cdn$/US$ exchange rates. In 2005, cash flow from operations was negatively impacted by the fire at Oil Sands.

At December 31, 2005, our net debt (short and long-term debt less cash and cash equivalents) was approximately $2.9 billion compared to $2.2 billion at December 31, 2004. Approximately $710 million of the increase in total net debt in 2005 was the result of capital spending exceeding cash from operating activities.

In 2005, we entered into a new $600 million credit facility agreement with a one year term and also renewed $200 million of our available credit and term loan facilities. Our undrawn lines of credit at December 31, 2005 were approximately $1.3 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 our efforts to maintain our ability to manage project costs and debt levels.

We believe we have the capital resources to fund our 2006 capital spending program of $3.5 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 largely financed from internal cash flow, which is dependent on commodity prices, production levels and other factors, as well as debt.

After 2006, to support our growth strategy and sustain operations, we are projecting an annual capital spending program of approximately $3.5 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 29 for additional factors that can have an impact on our ability to generate funds to support investing activities.

Aggregate Contractual Obligations

		Payments Due by Period			
($ millions)	Total	2006	2007-08	2009-10	Later Years
Fixed-term debt, commercial paper [1]	2 977	910	401	—	1 666
Capital leases	30	1	2	2	25
Interest payments on fixed-term debt, commercial paper and capital leases [1]	2 429	157	241	223	1 808
Employee future benefits [2]	457	33	74	84	266
Asset retirement obligations [3]	1 221	54	101	72	994
Non-cancellable capital spending commitments [4]	240	240	—	—	—
Operating lease agreements, pipeline capacity and energy services commitments [5]	5 408	258	507	529	4 114
Total	**12 762**	**1 653**	**1 326**	**910**	**8 873**

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 be terminated on short notice. Commodity purchase obligations for which an active, highly liquid market exists and which are expected to be re-sold shortly after purchase, are one example of excluded items.

(1) Includes $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 4.0% to 4.6% on $600 million of our medium term notes. Approximately $890 million of commercial paper with an effective interest rate of 3.2% was issued and outstanding at December 31, 2005.

(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 $240 million at the end of 2005. In addition to capital projects, we spend maintenance capital to sustain our current operations. In 2006, we anticipate spending approximately $700 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 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, 2005, we were in compliance with all covenants and our debt ratings were investment grade with a stable outlook. For more information, see page 24.

Significant Capital Project Update

We spent $2.8 billion ($3.2 billion including the cost of the fire rebuild and capitalized interest) on capital investing activities in 2005 compared to $1.825 billion in 2004. A summary of the progress on our significant projects under construction is provided below. All projects listed below have received Board of Directors approval.

Description	Cost Estimate ($ millions)[1]	Spent in 2005 ($ millions)	Total Spent to Date ($ millions)	Status[1]
Oil Sands				
Millennium vacuum unit	425	60	450	Project was completed on budget and on schedule. [2]
Firebag Stage 2	515	140	540	Project was completed on budget and on schedule, commissioning is underway. [2]
Coker Unit [3]	2 100	530	930	Project is on schedule and on budget.
Firebag Cogeneration and expansion	400	95	120	Project is on schedule and on budget.
EM&R				
Diesel desulphurization and oil sands integration	800	295	475	Project is on schedule and on budget.
R&M				
Diesel desulphurization and oil sands integration	465 (US$390)	285 (US$235)	420 (US$340)	Project cost estimate has been revised from $360 (US$300).

(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) Total project cost is subject to change until all accounts are final.

(3) Excludes costs associated with bitumen feed.

Variable Interest Entities and Guarantees and Off-balance Sheet Arrangements

At December 31, 2005, 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 $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, 2005, $340 million (2004 – $170 million) in outstanding accounts receivable had been sold under the program. Under the recourse provisions, we provide indemnification against credit losses for certain counterparties, for which indemnification did not exceed $58 million in 2005. A contingent liability has not 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, 2005, were $170 million and approximately $2,220 million, respectively. We recorded an after-tax loss of approximately $4 million on the securitization program in 2005 (2004 – $2 million; 2003 – $3 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 is the equipment sold to it and leased back by Suncor. The VIE was consolidated effective January 1, 2005. The initial lease term covers a period of seven years. We have provided a residual value guarantee on the equipment of up to $7 million should we elect not to repurchase the equipment at the end of the lease term. Had we elected to terminate the lease at December 31, 2005, the total cost would have been $21 million (2004 – $25 million). Annualized equipment lease payments in 2005 were $5 million (2004 – $6 million; 2003 – $4 million).

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 2006, management will focus on the following operational priorities:

- Increase annual average Oil Sands production to 260,000 bpd at an average cash operating cost of $16.00 to $16.75 per barrel, assuming a natural gas price of US$6.75/mcf at Henry Hub.
- Increase natural gas production to an average of 205 to 210 mmcf/d. We will continue to focus on deep gas prospects.
- Advance plans for increased bitumen supply. Achieve full capacity operations from Firebag Stage 1 and a steady ramp up of production from Firebag Stage 2. On the mining side, we anticipate substantial completion of engineering for the new Steepbank mine extension and extraction facilities.
- Advance plans for increased upgrader capacity. Significant progress to take Suncor to 350,000 bpd in 2008 is anticipated with major progress on construction and vessel delivery. A regulatory hearing regarding our plans for increasing production to half a million barrels per day is anticipated, while engineering for that expansion progresses to the design specification stage.
- Advancing downstream integration plans. In 2006, we expect to complete modifications to the Commerce City and Sarnia refineries to allow low sulphur fuel production. The Commerce City refinery will undergo a major maintenance shutdown to support operational reliability and to tie in equipment that will enable it to process 10,000 to 15,000 bpd of Oil Sands sour crude blends. The Sarnia refinery will also undergo a major maintenance shutdown to support operational reliability.
- Focus on company-wide efficiency. To more seamlessly integrate operations and improve efficiency and productivity, we expect to complete the implementation of a company-wide enterprise resource planning (ERP) information and management system.

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. Pursuant to an agreement we concluded with the Government of Alberta during the third quarter of 2005, we settled the terms and conditions of our option to transition our base operations in 2009 to the generic bitumen-based royalty regime. This option was initially granted by the government in 1997, but was subject to finalizing certain terms of transition. Should we elect to move our base operations to the bitumen-based royalty in 2009, assuming no change to the current regime, we would 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. We have until late 2008 to decide if we will exercise this option.

In July 2004, we issued a statement of claim against the Crown, seeking, among other things, to overturn the government's decision on the royalty treatment of our Firebag in-situ operations. In February 2006, we advised the Government of Alberta that we had elected not to proceed with our claim relating to the royalty treatment of Firebag.

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, 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.

If prices rise, we would expect the percentage to increase somewhat. 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 and if we elect to exercise the bitumen royalty option referred to in the previous paragraph.

Anticipated Royalty Expense Based on Certain Assumptions

For the Period from 2006-2013

Crown Royalty Expense (based on percentage of total Oil Sands revenue) %		
2006-08	10-12	12-14
2009-13 (1)	5-7	6-8
WTI Price/bbl US$	40	50
Natural gas price per mcf at Henry Hub US$	6.50	7.50
Light/heavy oil differential of WTI at Cushing less Maya at the U.S. Gulf Coast US$	9.50	10.50
Cdn$/US$ exchange rate	0.80	0.85

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

Based on these same economic assumptions and our current capital spending plans, and assuming continuation of the current economic circumstances including no change to the current Alberta Crown royalty regime for oil sands, we would expect the 25% R-C royalty to apply to our existing Oil Sands base operations in future years and the 1% minimum royalty to apply to the Firebag project until the next decade.

Alberta Crown royalties 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. For example, our Alberta oil sands Crown royalty expense in 2006 and future years may be significantly impacted by the amount of outstanding business interruption insurance proceeds we receive, and the timing of the receipts. Therefore, 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 timing of when the Oil Sands operations will be fully cash taxable is highly dependent on crude oil commodity prices and capital invested. Using the assumptions outlined in the table above, we anticipate that our Oil Sands and NG operations will be partially cash taxable commencing in 2007. These operations will continue to be partially cash taxable until the next decade, at which point they are expected to become fully cash taxable. In any particular year, our Oil Sands and NG operations may be subject to some cash income tax due to the sensitivity to crude oil and natural gas commodity price volatility and the timing of recognition of capital expenditures for income tax purposes.

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. We currently estimate that in 2010 the impact of the Kyoto Protocol on Oil Sands cash operating costs would be an increase of about $0.20 to $0.27 per barrel. This estimate assumes a reduction obligation of 15% from 2010 business-as-usual energy intensity (1) and that the maximum price for carbon credits would, as the Government of Canada indicated in 2002, be capped at $15 per tonne of carbon dioxide equivalent until 2012. Based on these assumptions, we do not currently anticipate that the cost implications of federal and provincial climate change plans will have a material impact on our business or future growth plans.

The ultimate impact of Canada's implementation of the Kyoto Protocol, however, remains subject to numerous risks, uncertainties and unknowns. These include the outcome of discussions between the federal and provincial governments, the form, impact and effectiveness of implementing legislation, the ultimate allocation of reduction obligations among economic sectors, and other details of Canada's implementation plan, as well as international developments. In addition, the Government of Canada has not indicated what, if any, limitations will be placed on the price of carbon

(1) Reflects the level of greenhouse gas emissions that would have occurred in the absence of energy efficiency and process improvements after 2000.

credits after 2012. It is not possible to predict how these and other Kyoto Protocol-related issues will ultimately be resolved.

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, stakeholder support for growth plans, extreme winter weather, regional labour issues and other issues discussed within Risk Factors for each of our business segments. A more detailed discussion of risk factors is presented in our most recent Annual Information Form/Form 40-F, filed with securities regulatory authorities.

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 2003 to 2005 the monthly average price for benchmark WTI crude oil ranged from a low of US$28.10/bbl to a high of US$65.55/bbl. During the same three-year period, the natural gas Henry Hub benchmark monthly average price ranged from a low of US$4.49/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 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 2005, a $0.01 change in the Cdn$/US$ exchange rate would change earnings by approximately $11 million after-tax.

During 2005, the strengthening of the Canadian dollar against the U.S. dollar resulted in a $31 million after-tax foreign exchange gain on our U.S. dollar denominated debt.

Our U.S. capital projects are expected to be partially funded from Canadian operations. A weaker Canadian dollar would result in a higher funding requirement for these projects.

Sensitivity Analysis [1]

	2005 Average	Change	Approximate Change in Cash Flow from Operations ($ millions)	Approximate Change in After-tax Earnings ($ millions)
Oil Sands				
Price of crude oil ($/barrel) [2]	$53.81	US$1.00	39	25
Sweet/sour differential ($/barrel)	$14.55	US$1.00	25	16
Sales (bpd)	165 300	1 000	12	8
Natural Gas				
Price of natural gas ($/mcf) [2]	$8.57	0.10	5	3
Production of natural gas (mmcf/d)	190	10	21	10
Energy Marketing and Refining – Canada				
Refining/wholesale margin (cpl) [2]	7.6	0.1	5	3
Refining and Marketing – U.S.A.				
Refining/wholesale margin (cpl)	9.0	0.1	5	3
Consolidated				
Exchange rate: Cdn$/US$	0.83	0.01	33	9

(1) The sensitivity analysis shows the main factors affecting Suncor's annual cash flow from operations and earnings based on actual 2005 operations. The table illustrates the potential financial impact of these factors applied to Suncor's 2005 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 and options to hedge against the potential adverse impact of changing market prices due to variations in underlying commodity indices. We also 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 gain market information and 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.

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 has been the subject of periodic management reviews to determine the continued need for hedging in light of our tolerance for exposure to market volatility as well as the need for stable cash flow to finance future growth. In the first quarter of 2004, the Board of Directors suspended the strategic crude oil hedging program. Crude oil hedges in place at the time fixed the price on 36,000 bpd of crude oil at an average price of US$23/bbl for 2005 (79,000 bpd at an average price of US$21 to US$24/bbl in 2004). These contracts expired on December 31, 2005.

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 permit us to fix a price or range of prices for a percentage of our total production of crude for specified periods of time. At December 31, 2005 we had entered into US$ WTI agreements covering 7,000 bpd of crude oil beginning January 1, 2006 and ending December 31, 2007. Prices for these barrels are fixed within a range of US$50/bbl to an average of approximately US$93/bbl WTI. We have continued to enter into crude oil hedges during the first quarter of 2006. As at March 1, 2006, crude oil hedges totalling 50,000 bpd of production were outstanding for the remainder of 2006 and 2007. Prices for these barrels are fixed within a range of US$50/bbl to an average of US$91.70/bbl. We intend to consider additional costless collars of up to 30% of our crude oil production if strategic opportunities are available.

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. 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. 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 Consolidated Statements of Earnings. In 2005, crude oil hedging decreased our net earnings by $337 million compared to a decrease of $397 million in 2004 (2003 – decrease of $155 million).

Crude oil hedge contracts outstanding at December 31, 2005 were as follows:

	Quantity (bpd)	Average Price (US$/bbl)[a]	Revenue Hedged (Cdn$ millions)[b]	Hedge Period[c]
Costless collars	7 000	50.00 – 92.57	149 – 276	2006
Costless collars	7 000	50.00 – 92.57	149 – 276	2007

(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, 2005. 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	2005 Effective Interest Rate
Swap of 6.70% Medium Term Notes to floating rates	200	2011	4.0%
Swap of 6.80% Medium Term Notes to floating rates	250	2007	4.6%
Swap of 6.10% Medium Term Notes to floating rates	150	2007	4.0%

In 2005, these interest rate swap transactions reduced pretax financing expense by $14 million compared to a pretax reduction of $17 million in 2004 (2003 – $12 million pretax).

At December 31, 2005, we had also hedged a portion of our euro exposure created by the anticipated purchase of equipment for a total of $31 million euros in 2006 and 2007.

Fair Value of Strategic Derivative Hedging Instruments The fair value of derivative hedging instruments is the estimated amount, based on broker quotes and 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:

($ millions)	**2005**	2004
Revenue hedge swaps and collars	**(4)**	(305)
Margin hedge swaps	**1**	5
Interest rate swaps and foreign currency forwards	**22**	36
	19	(264)

We also use derivative instruments to hedge risks specific to individual transactions. The estimated fair value of these instruments was $5 million at December 31, 2005, compared to $9 million at December 31, 2004.

Energy Trading Activities Energy trading activities focus on the commodities we produce. In addition to financial derivatives used for hedging activities, we also use energy derivatives to gain market information and earn trading revenues. These energy trading activities are accounted for using the mark-to-market method, and as such, physical and financial energy contracts are recorded at fair value at each balance sheet date. During 2005, we recorded a net pretax gain of $5 million compared to a pretax gain of $11 million in 2004 (2003 – pretax loss of $3 million) related to the settlement and revaluation of financial energy trading contracts. In 2005, the settlement of physical trading activities resulted in a net pretax gain of $15 million compared to a net pretax gain of $12 million in 2004 (2003 – $2 million net pretax gain). These gains were included as energy marketing and trading activities in the Consolidated Statements of Earnings. Net of related general and administrative costs, the combination of these activities resulted in 2005 net after-tax earnings of $11 million compared to net after-tax earnings of $12 million in 2004 (2003 – $2 million after-tax loss).

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

($ millions)	**2005**	2004
Energy trading assets	**82**	26
Energy trading liabilities	**70**	9
Net energy trading assets	**12**	17

The valuation of the above contracts was based on actively quoted prices and 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:

($ millions)	**2005**	2004
Derivative contracts not accounted for as hedges	**82**	7
Unrecognized derivative contracts accounted for as hedges	**30**	21
Total	**112**	28

Environmental Regulations

Environmental laws affect nearly all aspects of our operations, imposing certain standards and controls on activities relating to oil and gas mining, in-situ and conventional exploration, development and production. Environmental laws also affect refining, distribution and marketing of petroleum products and petrochemicals and require companies engaged in those activities to obtain necessary permits to operate. Environmental assessments and approvals are required before initiating most new projects or undertaking significant changes to existing operations.

In addition to these specifically known requirements, we expect that changes to environmental laws could impose further requirements on companies operating in the energy industry. Some of the issues include the possible cumulative impacts of oil sands development in the Athabasca region; the need to reduce or stabilize various emissions; issues relating to global climate change, including the uncertainties and risks associated with Canada's implementation of the Kyoto Protocol, and uncertainties associated with predicting emission intensity levels from our future production; and other potential impacts of government regulation in areas such as land reclamation and restoration, water quality and usage, and reformulated fuels to support lower vehicle emissions. Changes in environmental laws could have an adverse effect on us in terms of product demand, product formulation and quality, methods of production, and distribution and operating costs. The complexity of these issues makes it difficult to predict their future impact.

We anticipate capital expenditures and operating expenses could increase in the future as a result of the implementation of new and increasingly stringent environmental regulations.

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.

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.

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.

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

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.

Overburden

As part of the process of mining oil sands, it is necessary to remove surface material such as muskeg, glacial deposits and sand. This surface material is referred to as overburden, removal of which precedes mining of the oil sands deposits. Accordingly, the quantity of overburden removed in a given period may not bear any relationship to the quantity of oil sands mined in the period, and as such the cash outlays can be different than the amount amortized. In 2005, the overburden amortization charge was $178 million (2004 – $225 million; 2003 – $208 million) compared with actual cash overburden spending of $287 million (2004 – $222 million; 2003 – $175 million). Oil Sands overburden amortization is reported as part of DD&A in the Consolidated Statements of Earnings. Deferred overburden costs are reported as part of "deferred charges and other" in the Consolidated Balance Sheets.

To ensure that each tonne of oil sands mined is allocated a proportionate share of overburden removal costs, we use the deferral method of accounting for overburden removal costs whereby all such costs are initially set up as a deferred charge.

To allocate the deferred overburden charges, a life of mine approach is used for each mine pit, relating the removal of all overburden (on a volume basis) to the mining of all of the oil sands ore on leases where there is regulatory approval (on a tonnage basis). By adopting this approach, an overburden "stripping ratio" is calculated that relates overburden removal costs to all proved and probable oil sands ore reserves. Over time, through a combination of increased mine areas, additional drilling activity and operational experience, we have seen our stripping ratios vary, which can increase or decrease the overburden amortization costs charged to the earnings statement. In 2005, the stripping ratio decreased by approximately 10% due to new operational information and mine plan changes. The effects of the decreased stripping ratio were offset by higher per unit overburden removal costs. The $135 million increase in the amount of overburden deferred in 2005 compared to 2004 is therefore primarily due to increased overburden volumes moved (see page 43).

Our existing policy of accounting for overburden may be revised in 2006. Refer to "Recently Issued Canadian Accounting Standards" on page 39.

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 5.6% (2004 – 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 reviews of Oil Sands and NG completed in the fourth quarter of 2005, we increased our estimated undiscounted total obligation to approximately $1.2 billion from the previous estimate of $1.1 billion. The increase was primarily due to a change in the Oil Sands estimate from $940 million to $1,080 million, primarily reflecting increased estimated costs related to consolidated tailings projects and increased land reclamation and reforestation costs. The majority of the costs in Oil Sands are projected to occur over a time horizon extending to approximately 2060. In 2006, these changes in the ARO estimate are anticipated to result in additional after-tax expenses of approximately $4 million. The discounted amount of our ARO liability was $543 million at December 31, 2005 compared to $476 million at December 31, 2004.

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 under way. 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.

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 on page 36).

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 31st bitumen pricing and assumes we will elect to transfer to a bitumen-based Crown royalty effective at 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 Crown royalty based on bitumen, rather than synthetic crude oil (for a full discussion of our Oil Sands Crown royalties, see page 27).

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 on 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. These assumptions use a posted benchmark oil price as at December 31, but apply a differential generally intended to represent a normalized annual average for the year ("Annual Average Differential Pricing"), rather than a point in time differential, in accordance with Canadian Securities Administrators Staff Notice 51-315 ("CSA Staff Notice 51-315"). 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 four ways. Reserves from our Firebag in-situ leases under our voluntary disclosure:

- are disclosed on a gross basis as well as the required net basis under U.S. disclosure requirements;
- are converted from barrels of bitumen under U.S. disclosure requirements to barrels of synthetic crude oil for aggregation purposes only;
- are evaluated based on 2005 Annual Average Differential Pricing assumptions, in accordance with CSA Staff Notice 51-315, versus Constant Cost and Pricing assumptions pursuant to U.S. disclosure requirements; and
- 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 (see "Required U.S. Oil and Gas and Mining Disclosure – Proved Conventional Oil and Gas Reserves" on page 36).

Under our voluntary disclosure, using 2005 Annual Average Differential Pricing, our Firebag in-situ reserves were also determined to be economic and accordingly, were disclosed under "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 and Mining Disclosure" and "Voluntary Oil Sands Reserves Disclosure" will 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.

All of our reserves have been evaluated as at December 31, 2005 by independent petroleum consultants, GLJ Petroleum Consultants Ltd. (GLJ). In reports dated February 21, 2006 ("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, and pursuant to CSA Staff Notice 51-315, using 2005 Annual Average Differential 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 3D seismic control (or 40-acre spacing without 3D seismic control) while our probable reserves are delineated to within a 320-acre spacing with 3D seismic control (or 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 under way but have not yet received final approval from our Board.

In a report dated February 21, 2006 ("GLJ NG Report"), GLJ also evaluated our proved reserves of natural gas, natural gas liquids and crude oil (other than reserves from mining leases and the Firebag in-situ reserves) as at December 31, 2005.

More information about the evaluation of our reserves by GLJ, as well as additional oil and gas data, is available in our most recent Annual Information Form, which is filed with the United States Securities and Exchange Commission under cover of Form 40-F.

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

Net reserves represent Suncor's undivided percentage interest in total reserves after deducting Crown Royalties, freehold and overriding royalty interests. Reserve estimates are based on assumptions about pricing, production levels, operating costs and capital expenditures. These assumptions reflect market conditions, as required, at December 31, 2005 which could differ significantly from other points in time throughout the year, or future periods. These market 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

	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, 2004	939	916	847	837	1 786	1 753
Revisions of previous estimates	645	575	(439)	(438)	206	137
Extensions and discoveries	—	—	488	463	488	463
Production	(56)	(51)	—	—	(56)	(51)
December 31, 2005	**1 528**	**1 440**	**896**	**862**	**2 424**	**2 302**

(1) Synthetic crude oil reserves are based upon a net coker, or synthetic crude oil yield from bitumen of 80% (2004 – 80% to 81%).

(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 relative value of Crown, freehold and overriding royalty burdens under constant December 31st pricing and assumes we will 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 of conventional oil and gas activities only, and therefore our Oil Sands mining activities are excluded, while our Firebag in-situ 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, 2004	— (3)	8	8	446
Revisions on previous estimates (5)	639	—	639	14
Purchases of minerals in place	—	—	—	—
Extensions and discoveries	—	—	—	40
Production	(7)	(1)	(8)	(50)
Sales of minerals in place	—	—	—	(1)
December 31, 2005	**632**	**7**	**639**	**449**

(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 Costs 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.

(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.

(5) Includes total infill drilling of 23 billion cubic feet (bcf) in 2005.

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 Firebag in-situ leases, from December 31, 2004 to December 31, 2005, based on the GLJ Oil Sands Reports, in accordance with CSA Staff Notice 51-315, using 2005 Annual Average Differential Pricing assumptions.

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, 2004	939	847	1 786	494	1 900	2 394	4 180
Revisions of previous estimates	645	(439)	206	73	(131)	(58)	148
Improved Recovery	—	—	—	—	368	368	368
Extensions and discoveries	—	488	488	—	—	—	488
Production	(56)	—	(56)	(6)	—	(6)	(62)
December 31, 2005	**1 528**	**896**	**2 424**	**561**	**2 137**	**2 698**	**5 122**

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, 2004	916	837	1 753	457	1 714	2 171	3 924
Revisions of previous estimates	575	(438)	137	105	(38)	67	204
Improved Recovery	—	—	—	—	353	353	353
Extensions and discoveries	—	463	463	—	—	—	463
Production	(51)	—	(51)	(6)	—	(6)	(57)
December 31, 2005	**1 440**	**862**	**2 302**	**556**	**2 029**	**2 585**	**4 887**

(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 aggregation 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 assumes we will 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 four 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 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;
- (c) are evaluated based on Annual Average Differential Pricing assumptions versus point-in-time Constant Cost and Pricing assumptions as at December 31. Accordingly, Firebag in-situ reserve estimates under "Required U.S. Oil and Gas and Mining Disclosure – Proved Conventional Oil and Gas Reserves" and Firebag in-situ proved reserve estimates in this table differ materially; and
- (d) 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.

Employee Future Benefits

We provide a range of benefits to our employees and retired employees, including pensions and other post-retirement health care and life insurance 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.

	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	(4)	4	(15)	17	7	(7)
Increase (decrease) to benefit obligation	—	—	(119)	140	35	(33)

Health care costs comprise a significant element of our post-employment benefit obligation and is an area where there is increasing cost pressure due to an aging North American population. We have assumed a 10% annual rate of increase in the per capita cost of covered health care benefits for 2005, 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	13	(11)

Control Environment

Based on their evaluation as of December 31, 2005, 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, 2005, there were no changes in our internal control over financial reporting that occurred during 2005 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.

We are in the process of implementing an enterprise resource planning (ERP) system in all of our businesses to facilitate our growth plan. The phased implementation is currently planned to be complete by the end of 2006. Implementing an ERP system on a widespread basis involves significant changes in business processes and extensive organizational training. We currently believe a phased-in approach reduces the risks associated with making these changes. We believe we are taking the necessary steps to monitor and maintain appropriate internal control over financial reporting during this transition period. These steps include deploying resources to mitigate internal control risks and performing additional verifications and testing to ensure data integrity.

In connection with the continued implementation of our ERP system, we expect there will be a significant redesign of our business processes during 2006, some of which relate to internal control over financial reporting and disclosure controls and procedures.

Change In Accounting Policies

Preferred Securities

On January 1, 2005, we retroactively adopted the Canadian accounting standard related to disclosure and presentation of financial instruments. Accordingly, our preferred securities, which were redeemed in March 2004, have been reclassified as long-term debt and the preferred dividends have been reclassified as financing expense. We have restated our property, plant and equipment and depreciation, depletion and amortization to reflect capitalized interest that would have been incurred and amortized had the preferred securities been classified as debt during the period in which they were outstanding. The impact of adopting this standard was an increase to property, plant and equipment of $37 million.

Consolidation of Variable Interest Entities

On January 1, 2005, we prospectively adopted Canadian Accounting Guideline 15 – "Consolidation of Variable Interest Entities" (VIE's). Accordingly, we consolidated the VIE related to the sale of equipment as described on page 26. The impact of adopting this standard was an increase to property, plant and equipment of $14 million, an increase to materials and supplies inventory of $8 million and an increase to long-term debt of $22 million. There was no impact to net earnings.

Recently Issued Canadian Accounting Standards

Non-monetary Transactions

In 2005, the Canadian Institute of Chartered Accountants (CICA) approved Handbook Section 3831 "Non-Monetary Transactions". Effective January 1, 2006, all non-monetary transactions must be measured at fair value (if determinable) unless the transaction lacks commercial substance, is an exchange of a product held for sale in the ordinary course of business, or is a product to be sold in the same line of business. Commercial substance exists when the company's future cash flows are expected to change significantly as a result of a transaction. We will be 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 natural gas will be recorded. The amount of the gross-up will be dependent on the prevailing prices for natural gas. Currently this transaction is recorded on a net basis in purchases of crude oil and products. Retroactive adjustment is prohibited by the standard.

Overburden Removal Costs

On February 16, 2006, the Emerging Issues Committee of the CICA approved an abstract regarding the treatment of overburden costs in the mining industry effective July 1, 2006. The proposed abstract would require the capitalization of overburden removal costs when such costs represent a betterment to the mine property by facilitating access to reserves in future periods. Costs are to be treated as variable production costs and expensed as incurred when no betterment exists. We currently amortize the cost of overburden removal using stripping ratios based on a life of mine approach. We are considering expensing overburden costs as incurred on a retroactive basis effective from January 1, 2006. With the exception of the impact on 2005 net earnings, the effect of adopting the standard is not expected to be significant. Net earnings in 2005 would be reduced by approximately $87 million due to increased amounts of overburden moved during the year.

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.

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, our presentation will be aligned with the current U.S. GAAP reporting as outlined in note 18 to our 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.

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 calls for sales of bitumen when production from mining and in-situ operations exceed upgrading capacity, assuming 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 of Oil Sands upgrading facilities.
- 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, reduce costs and reduce environmental impacts.

HIGHLIGHTS

Summary of Results

Year ended December 31

($ millions unless otherwise noted)	**2005**	2004	2003
Revenue	**3 965**	3 640	3 101
Production (thousands of bpd)	**171.3**	226.5	216.6
Average sales price ($/barrel)	**53.81**	42.28	37.19
Net earnings	**1 073**	994	887
Cash flow from operations	**1 895**	1 752	1 803
Total assets	**11 850**	9 067	7 970
Cash used in investing activities	**1 929**	1 087	1 060
Net cash surplus (deficiency)	**(257)**	737	799
ROCE (%) (1)	**24.3**	22.9	20.8
ROCE (%) (2)	**17.6**	18.8	17.4

(1) 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 56.

(2) Includes capitalized costs related to major projects in progress. See page 56.

2005 Overview

- In September 2005, we completed rebuilding portions of our Oil Sands plant that were damaged by fire on January 4, 2005. The recovery and planned maintenance work was completed on schedule and the plant was running at full capacity by the end of September.
- In October, we successfully commissioned an expansion of our Oil Sands facilities by adding a vacuum unit to Upgrader 2, increasing our capacity to 260,000 barrels per day (bpd) from 225,000 bpd. Construction was completed on schedule and on budget. See page 26.
- Our Firebag Stage 2 in-situ project entered the start-up phase, with first oil in the fourth quarter of 2005. Commercial operations are expected to commence in the first quarter of 2006. See page 26.

- 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 pair of cokers to Upgrader 2. Fabrication and placement of the coke drums is complete, and the project remains on schedule and within budget projections. See page 26.
- An application was filed with Alberta regulators to construct and operate a third Oil Sands upgrader, designed to increase our production capacity to 500,000 to 550,000 bpd by 2012. We also filed an application with Alberta regulators requesting permission to proceed with the Steepbank mine extension.

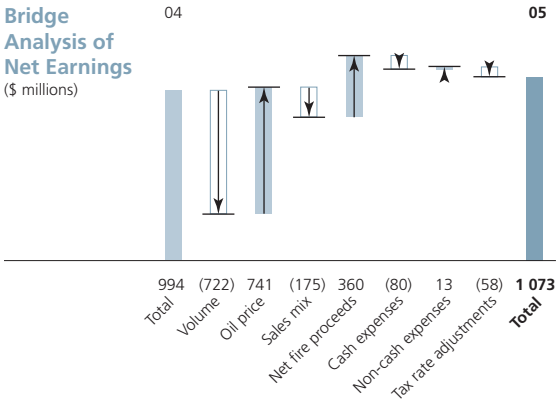
Analysis of Net Earnings

Net earnings were $1,073 million in 2005 compared to $994 million in 2004 (2003 – $887 million). The increase in net earnings was due primarily to high price realizations on the Oil Sands basket of products, reflecting higher benchmark WTI prices, the receipt of fire insurance proceeds and lower hedging losses. These positive factors were largely offset by widening light/heavy crude oil differentials, decreased production and sales volumes and a decrease in the sales mix of sweet crude oil and diesel fuel compared to sour crude oil and bitumen as a result of the fire.

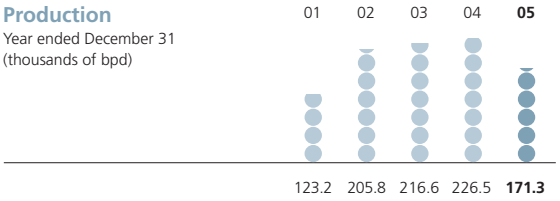
Oil Sands average production was 171,300 bpd in 2005, compared to 226,500 bpd in 2004. Sales volumes in 2005 averaged 165,300 bpd compared with 226,300 bpd in 2004. Lower sales volumes decreased 2005 net earnings by $722 million. The decrease in 2005 production and sales volumes was due largely to the effects of the January 4, 2005 fire that reduced production to an average of 122,000 bpd for the first nine months of the year. The build in inventory volumes during 2005 was primarily due to the expanded storage and production facilities that came online during the fourth quarter of 2005.

Sales volumes of higher value diesel fuel and sweet crude products decreased to 54% of total sales volumes in 2005 from 63% in 2004, reflecting the negative impact of the fire, increased bitumen sales from our in-situ operations and the start up of the vacuum unit expansion project. Starting in mid October 2005, all bitumen produced from our Firebag operations was upgraded. Prior to that, bitumen from Firebag was sold directly into the marketplace. The decrease in sweet products as a percentage of our total sales volumes decreased earnings by $175 million. As a result of the new vacuum unit, we anticipate that our sales mix of high value diesel fuel and sweet crude products in 2006 will be 56%[1] of our total sales volumes.

Bridge Analysis of Net Earnings
($ millions)



Production
Year ended December 31
(thousands of bpd)



(1) We continue to gain experience in operating facilities that were newly commissioned in late 2005, therefore there is more uncertainty in 2006 plans than in prior years.

Sales price realizations averaged $53.81 per barrel in 2005 (including the impact of pretax hedging losses of $535 million) compared with $42.28 per barrel in 2004 (including the impact of pretax hedging losses of $620 million). The average sales price realization was favourably impacted by stronger WTI benchmark crude oil prices as well as higher positive differentials for synthetic sweet crude oil and diesel fuel. These factors were partially offset by wider differentials on sour crude oil and bitumen blends, as well as the continued strengthening of the Canadian dollar compared to the U.S. dollar. As crude oil is sold based on U.S. dollar benchmark prices, the narrowing exchange rate decreased the Canadian dollar value of crude oil products.

The impact of the above pricing factors increased net earnings by $741 million in 2005.

Net Fire Proceeds

In 2005, we recognized $572 million in insurance proceeds, net of the write-off of damaged assets and related expenses. During 2005, we received $115 million (US$95 million) from our property loss policy and $594 million (US$500 million) in proceeds from our BI policies, including $175 million (US$150 million) received in January and February 2006. Net fire proceeds increased net earnings by $360 million. For further discussion of our insurance policies, see page 24.

Cash Expenses

Cash expenses increased to $1,325 million from $1,191 million in 2004 (2003 – $1,053 million). Expenses were higher year-over-year due to the following factors:

- Higher natural gas costs of approximately $110 million reflecting higher natural gas prices and increased gas consumption at our in-situ operations.
- Higher maintenance costs related to the upgrader that was not damaged by the fire to ensure reliability.
- Higher production volumes at our in-situ operations. This increased cash expenses by approximately $30 million reflecting increased staffing and maintenance. In addition, 2005 was the first full year of in-situ operations. In-situ costs incurred during the first quarter of 2004 were treated as project start-up costs.

Partially offsetting these negative factors:

- Purchases of crude oil and products decreased to $32 million in 2005 from $75 million in 2004. Purchases in 2004 included the repurchase of crude oil originally sold to a VIE in 1999.
- Taxes other than income taxes decreased by $21 million as a result of lower diesel fuel excise taxes reflecting lower sales volumes as a result of the fire.
- We were able to redeploy some of our mining resources to overburden removal as a result of the fire. Despite decreased production volumes, mining expenses decreased only slightly as the increased deferral of overburden costs were almost entirely offset by increased costs associated with mine maintenance projects.

Overall, increased cash expenses reduced net earnings by $80 million.

Royalties

Oil Sands Alberta Crown royalties were relatively unchanged at $406 million in 2005 compared to $407 million in 2004 (2003 – $33 million). Alberta Oil Sands Crown royalties are subject to change as policies arising from the government's position are finalized and audits of 2005 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. In addition, 2004 was a transition year for Oil Sands as the remaining amount of prior years' allowable costs carried forward of approximately $600 million were claimed in 2004 to reduce our 2004 Alberta Crown royalty obligation. No such carry forward of allowed costs existed for 2005 or subsequent years. For a further discussion on Crown royalties, see page 27.

Non-cash Expenses

Non-cash depreciation, depletion and amortization (DD&A) expense, including overburden amortization expense, decreased to $482 million from $505 million in 2004 (2003 – $459 million). The decrease was primarily due to lower overburden amortization of $47 million reflecting lower production volumes, partially offset by higher DD&A expenses from in-situ operations of $13 million. Lower non-cash expenses increased net earnings by $13 million.

Deferred overburden costs are amortized using stripping ratios that allocate the overburden costs to the tonnes of ore mined during the year. In 2005, Oil Sands average overburden removal stripping ratio was 0.47 cubic metres of overburden for every tonne of ore mined, compared to 0.52 cubic metres per tonne in 2004. The decreased stripping ratio year-over-year was primarily due to updated drilling results that provided more detailed information on proved reserves. Overburden amortization decreased to $178 million in 2005 compared with $225 million in 2004, primarily reflecting lower production volumes.

As a result of new Canadian and U.S. GAAP requirements, we are considering expensing overburden costs as incurred. See page 39.

Tax Adjustments

In 2004, non-cash income tax expense was reduced by $53 million relating to reductions in the Alberta provincial tax rate. Excluding the 2004 rate change, the remaining tax rate adjustment was due to a small change in the effective tax rate in 2005 compared to 2004 and other minor differences.

Cash Operating Costs

In 2005, we reported cash operating costs for upgraded production (base operations) as well as cash costs from in-situ operations. Cash operating costs for base operations increased to $1,123 million ($19.50 per barrel) in 2005 compared to $949 million ($11.95 per barrel) in 2004, primarily due to the same factors affecting cash expenses discussed previously. In addition, per barrel cash costs have increased due to the effect of the fire on production volumes.

Natural gas purchases for base operations averaged approximately 66 million cubic feet per day (mmcf/d) in 2005, consistent with the prior year. Oil Sands natural gas costs increased to $8.95 per mcf in 2005 from $6.74 per mcf in 2004, increasing cash costs by approximately $1.75 per barrel.

Net Cash Surplus (Deficiency) Analysis

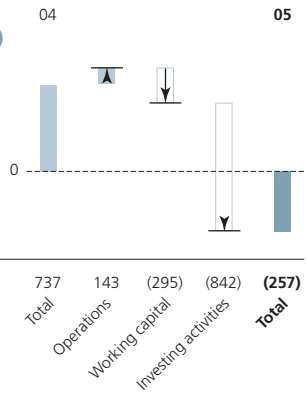
Cash flow from operations was $1,895 million in 2005 compared to $1,752 million in 2004 (2003 – $1,803 million). Excluding the impact of non-cash income tax adjustments, the increase was due to the same factors that increased net earnings, offset by higher cash overburden and reclamation spending, and higher pension funding requirements.

Net working capital increased by $223 million in 2005 compared to a decrease of $72 million in 2004 (2003 – $56 million). Higher accounts receivable due to higher sales volumes and higher price realizations in the final month of 2005 compared to 2004 were only partially offset by increased accounts payable and accrued liabilities related to increased capital spending in 2005.

Cash flow used in investing activities increased to $1,929 million in 2005 from $1,087 million in 2004 (2003 – $1,060 million). During 2005, capital spending related primarily to the reconstruction of assets damaged by the fire, higher sustaining capital for extraction projects, construction of Firebag Stage 2, the Millennium vacuum unit, engineering and preliminary construction of the Millennium Coker Unit and the debottlenecking of our Steepbank extraction assets.

Combined, the above factors resulted in a net cash deficiency of $257 million in 2005, compared with a surplus of $737 million in 2004 (2003 – $799 million surplus).

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



Outlook

Our Oil Sands operations continue to be the focus of our business strategy. In 2006, we anticipate our oil sands production will average 260,000 bpd from our existing upgrading assets. 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 2006, we have budgeted capital spending of approximately $2.5 billion, of which $700 million is slated for sustaining projects with the remainder earmarked for growth. This growth spending supports the goal of increasing production to 350,000 bpd in 2008, while laying the groundwork for further expansion later in the decade.

Expansion to 350,000 bpd

Work to increase production capacity to 350,000 bpd in 2008 is proceeding on schedule. During 2006, construction is planned to continue on the coker unit project, the second stage of our Firebag in-situ project will move into commercial operations and we intend to continue construction on the recently approved cogeneration facility that will provide additional steam and capacity to our in-situ operations. For an update on the progress of these significant capital projects, see page 26.

In addition to the on-going expansion of 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, slated to take effect in 2008. Under the agreement, Oil Sands will process at least 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 planning for expansion beyond 2008, we filed regulatory applications in 2005 to construct a third upgrader, a key step to increasing production capacity to 500,000 to 550,000 bpd in the 2010 to 2012 time frame. The preliminary cost estimate for this project of $5.9 billion [(1)] is subject to change. This estimate does not include costs for related bitumen supply projects to feed the upgrader. Approval by regulators and Suncor's Board of Directors is required before the project can proceed.

Mine Extension

In March 2005, we filed an application for approval to construct and operate an extension of our Steepbank mine. The proposed development would replace ore production that is expected to be depleted prior to the end of the decade. Currently, capital development costs are estimated at $350 million, and are subject to change. Approval by regulators and our Board of Directors is required before construction can proceed.

In 2005, Oil Sands filed a renewal application with regulators for a 10-year renewal of our operating licence.

(1) This cost estimate has a range of uncertainty of +50/–30%. For a discussion of this estimation process see page 26.

Risk Factors Affecting Performance

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

- Final amount and timing of the settlement and payment of insurance proceeds related to fire damage and interruption of business at Oil Sands in connection with the January 2005 fire.
- Our ability to finance Oil Sands growth in a volatile commodity pricing environment. Also refer to "Liquidity and Capital Resources" on page 24.
- 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 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.
- 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.
- Our relationship with our trade unions. Work disruptions have the potential to adversely affect Oil Sands operations and growth projects.

These factors and estimates are subject to certain risks, assumptions and uncertainties discussed on page 58 under Forward-looking Statements. Also refer to Suncor Overview, Risk Factors Affecting Performance on page 29.

NATURAL GAS

Our 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.
- Developing new, low-capital business opportunities.

NG's long-term goal is to achieve a sustainable return on capital employed (ROCE) [1] of 12%-15% at mid-cycle prices of US$5.00 to US$5.50 per thousand cubic feet (mcf). To offset company-wide natural gas purchases, NG is targeting production increases of 3% to 5% per year.

HIGHLIGHTS

Summary of Results

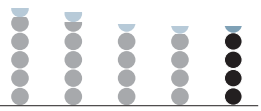
Year ended December 31 ($ millions unless otherwise noted)	**2005**	2004	2003
Revenue	**679**	567	512
Natural gas production (mmcf/d)	**190**	200	187
Average natural gas sales price ($/mcf)	**8.57**	6.70	6.42
Net earnings	**155**	115	120
Cash flow from operations	**412**	319	298
Total assets	**1 307**	967	765
Cash used in investing activities	**344**	251	167
Net cash surplus	**63**	67	143
ROCE (%) [1]	**30.7**	27.1	29.2

(1) ROCE for Suncor operating segments is calculated in a manner consistent with consolidated ROCE as reconciled in Non GAAP Financial Measures. See page 56.

2005 Overview

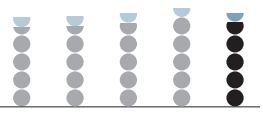
- Production averaged 190 million cubic feet per day (mmcf/d) in 2005 compared to 200 mmcf/d in 2004 and company-wide purchases for internal consumption of approximately 138 mmcf/d. Production targets for 2005 were negatively impacted by unplanned maintenance and weather related drilling delays that affected the western upstream oil and gas Canadian industry.
- In 2005, construction of the North Cabin Pipeline that connects the Cabin Creek and Solomon fields in the Alberta Foothills to the Simonette gas plant was completed. In addition an expansion and maintenance shutdown at the Simonette gas plant was completed.
- During 2005 we continued the divestment of non-core properties with proceeds of $21 million received in 2005.
- Subsequent to year-end, we disposed of 15% of our interest in the South Rosevear gas plant for proceeds of $12 million. We currently retain a 60.4% interest and continue to operate the gas plant.

Total Net Proved Reserves
Year ended December 31
(millions of boe) [2]



	01	02	03	04	**05**
Natural gas liquids and crude oil	10	10	8	8	**7**
Natural gas	91	86	76	74	**75**
Total	101	96	84	82	**82**

Production
Year ended December 31
(thousands of boe/d) [2]



	01	02	03	04	**05**
Natural gas liquids and crude oil	3.9	3.9	3.7	3.5	**3.2**
Natural gas	29.5	29.8	31.2	33.3	**31.6**
Total	33.4	33.7	34.9	36.8	**34.8**

(2) For details on barrels of oil equivalent (boe), see page 17.

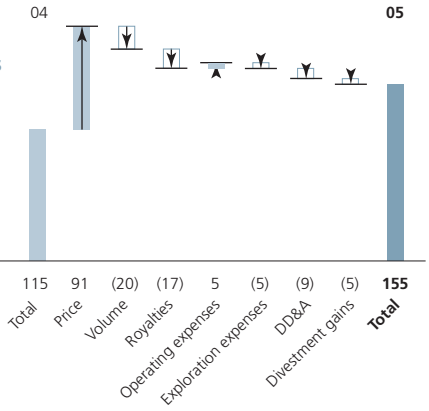
Analysis of Net Earnings

NG net earnings were $155 million in 2005, compared to $115 million in 2004 (2003 – $120 million). Higher realized natural gas and liquids prices were partially offset by lower sales volumes, higher royalty expenses, higher depreciation, depletion and amortization (DD&A), higher lifting costs, higher exploration expenses and lower divestment gains. Earnings in 2004 were negatively impacted by costs associated with the final arbitrated settlement of terminated gas marketing contracts related to Enron Corporation's bankruptcy in December 2001.

In 2005, the average realized price for natural gas was $8.57 per mcf, compared to an average of $6.70 per mcf in 2004, reflecting higher benchmark natural gas prices. Price realizations for NG's crude oil and natural gas liquids production were also higher in 2005 due to higher benchmark crude oil prices. The combined impact of the above pricing factors increased net earnings in 2005 by $91 million.

NG's average natural gas production was 190 mmcf/d in 2005 compared to 200 mmcf/d in 2004. Including liquids, total 2005 production was 34,800 boe/d compared to 36,800 boe/d in 2004. The decrease in 2005 production was primarily due to unplanned maintenance issues and weather related delays in drilling during the first half of the year. Lower production volumes negatively impacted 2005 net earnings by $20 million.

Bridge Analysis of Net Earnings
($ millions)



Expenses

Royalties on NG production were $149 million ($11.72 per boe) in 2005, compared to $124 million ($9.22 per boe) in 2004 (2003 – $106 million; $8.32/boe). The increase was due to higher sales price realizations, caused by higher benchmark commodity prices, partially offset by lower production.

Operating costs were $93 million in 2005 compared to $100 million in 2004 (2003 – $73 million). Total operating costs were higher in 2004 due to an arbitrated settlement of terminated gas marketing contracts related to Enron Corporation's bankruptcy in December 2001 that reduced 2004 after-tax earnings by $12 million. Excluding the Enron settlement, operating costs were higher in 2005 due to higher lifting costs as a result of higher planned and unplanned maintenance.

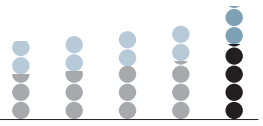
Exploration expenses increased to $46 million in 2005 from $38 million in 2004 (2003 – $40 million). Higher dry hole expenses were only partially offset by lower seismic expenditures.

DD&A expense was $130 million in 2005 compared to $115 million in 2004 (2003 – $91 million). The increase was due to a higher cost base subject to depletion and a lower proved reserve base, as well as higher amortization expense related to unproven lands.

Divestment gains were $12 million in 2005 ($8 million after-tax) compared to $19 million ($13 million after-tax) in 2004 (2003 – $12 million; $8 million after-tax). Divestments in 2005 reflect sales of non-core properties, whereas 2004 divestments primarily relate to the sale of a 62.5% interest in our Simonette gas plant for proceeds of $19 million.

In total, the above noted items reduced net earnings by $31 million.

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



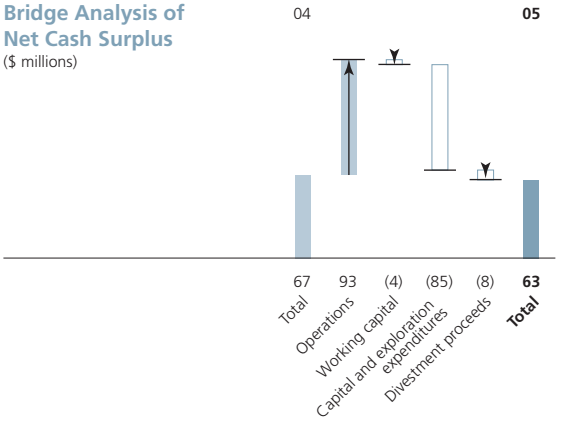
	01	02	03	04	**05**
Administration	2.21	2.34	2.35	2.39	**2.52**
Lifting	2.96	3.15	3.48	3.84	**4.95**
Total	5.17	5.49	5.83	6.23	**7.47**

Net Cash Surplus Analysis

NG's net cash surplus was $63 million in 2005 compared with $67 million in 2004 (2003 – $143 million). Cash flow from operations increased to $412 million compared with $319 million in the prior year (2003 – $298 million), largely due to higher commodity prices, partially offset by lower production and higher royalties.

Cash used in investing activities increased to $344 million compared with $251 million in 2004 (2003 – $167 million) as a result of higher drilling, exploration and facilities costs.

Bridge Analysis of Net Cash Surplus
($ millions)



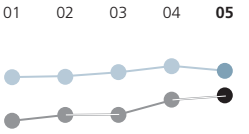
Outlook

NG plans to increase natural gas production to 205 to 210 mmcf/d in 2006 to offset our growing internal natural gas demands.

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 $325 million in capital spending for exploration and development in 2006.

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



	01	02	03	04	**05**
Production	177	179	187	200	**190**
Purchases	87	99	100	130	**138**

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.
- Risks and uncertainties associated with obtaining regulatory approval for exploration and development activities in Canada and with our indirectly wholly owned subsidiary in the United States. These risks could add to costs or cause delays to 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.
- 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.

These factors and estimates are subject to certain risks, assumptions and uncertainties discussed on page 58 under Forward-looking Statements. Refer to the Suncor Overview, Risk Factors Affecting Performance on page 29.

(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 metre 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 the Oil Sands and NG operations.

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.

As a marketing channel for our refined products, EM&R's Ontario retail network generated approximately 57% of EM&R's total 2005 sales volume of 96,000 bpd. The retail networks are comprised of 275 Sunoco-branded retail service stations, 28 Sunoco-branded Fleet Fuel Cardlock sites, and two 50% retail joint venture businesses [(1)] that operate 149 Pioneer-branded retail service stations, 50 UPI-branded retail service stations and 14 UPI bulk distribution facilities for rural and farm fuels. Approximately 39% of EM&R's refined product sales in 2005 were wholesale and industrial sales. Sun Petrochemicals Company (SPC), a 50% joint venture between a Suncor subsidiary and a Toledo, Ohio-based refinery, generated the remaining 4% of sales.

HIGHLIGHTS

Summary of Results

Year ended December 31 ($ millions unless otherwise noted)	**2005**	2004	2003
Revenue	**4 299**	3 460	2 936
Refined product sales (millions of litres)			
Sunoco retail gasoline	**1 656**	1 665	1 599
Total	**5 570**	5 643	5 477
Net earnings (loss) breakdown:			
Total earnings excluding energy, marketing and trading activities	**30**	68	67
Energy marketing and trading activities	**11**	12	(2)
Tax adjustments	**—**	—	(12)
Total net earnings	**41**	80	53
Cash flow from operations	**152**	188	164
Cash used in investing activities	**436**	259	135
Net cash surplus (deficiency)	**(328)**	(21)	29
ROCE (%) [(1)]	**8.1**	14.6	10.3
ROCE (%) [(2)]	**5.2**	13.6	10.3

(1) 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 56.

(2) Includes capitalized costs related to major projects in progress. See page 56.

(1) Pioneer Group Inc., is an independent company with which we have a 50% joint venture partnership. UPI Inc. is a 50% joint venture with GROWMARK Inc., a Midwest U.S. retail farm supply and grain marketing cooperative.

2005 Overview

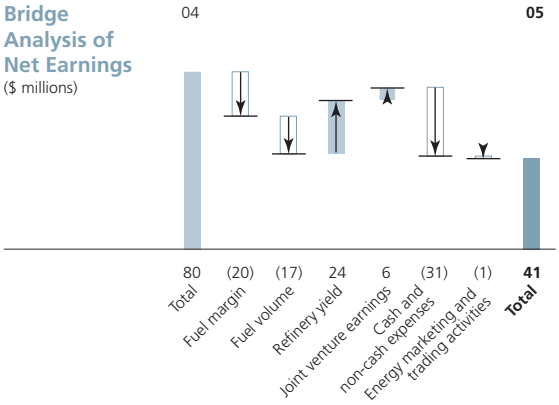
- During 2005, construction continued on the diesel desulphurization unit at the Sarnia refinery. This project is intended to meet federal low-sulphur diesel fuel regulations that take effect in 2006. The project, estimated to cost $800 million, is also expected to enable the refinery to process approximately 40,000 bpd of Oil Sands sour crude blends in 2007. See page 26.
- In April 2005, we received final environmental approvals from federal and provincial governments for our ethanol production facility in the Sarnia region. Construction of the $120 million plant began in June 2005 and is expected to be completed in June 2006. Natural Resources Canada has contributed $19 million towards this project through their Ethanol Expansion Program.
- During March and April 2005, we completed a 24-day planned maintenance shutdown at our Sarnia refinery.

Analysis of Net Earnings

EM&R results include the impact of our third party energy marketing and trading activities that are discussed separately on page 51.

EM&R's net earnings decreased to $41 million in 2005 from $80 million in 2004 (2003 – $53 million). This decrease was primarily due to lower refining margins, lower sales volumes, lower refinery utilization, lower mark-to-market gains on inventory related derivatives, and higher cash refinery operating costs, primarily due to higher energy costs as a result of high natural gas prices. These negative impacts were partially offset by lower third party refined product purchase volumes and higher joint venture earnings.

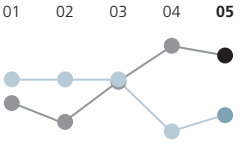
Bridge Analysis of Net Earnings
($ millions)



Margins

After-tax refined product margins decreased by $20 million in 2005 compared to 2004, due to lower refining margins on gasoline, chemicals, and other products such as fuel oil and propane, partially offset by increased refining margins in diesel and jet fuel. Refining margins on proprietary refined products averaged 7.6 cents per litre (cpl) in 2005, compared to 8.0 cpl in 2004. Sunoco-branded retail gasoline margins averaged 5.1 cpl in 2005, compared with 4.4 cpl in 2004. The increase was primarily due to an improved competitive pricing environment in the greater Toronto area and tight refined product supply due to hurricanes on the U.S. Gulf Coast during the summer of 2005.

Margins
Year ended December 31
(cpl)



	01	02	03	04	**05**
Retail gasoline margin	6.6	6.6	6.6	4.4	**5.1**
Refining margin	5.7	4.8	6.5	8.0	**7.6**

Volumes

Total sales volumes averaged 96,000 bpd (15,200 cubic metres per day) in 2005, down slightly from 97,000 bpd (15,400 cubic metres per day) in 2004, resulting in a decrease in net earnings of $17 million. Higher sales volumes of heavy fuel oils and diesel were more than offset by lower sales volumes of gasoline and propane. Total gasoline sales volumes in the Sunoco-branded retail network decreased to 1,656 million litres in 2005 from 1,665 million litres in 2004. Average Sunoco-branded service station site throughput was 6.3 million litres per site in 2005 compared to 6.2 million litres per site in 2004. 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 19% in 2005 (2004 – 19%). Approximately 96% of EM&R's refined products were sold to the Ontario market in 2005.

Refinery Utilization

Overall refinery utilization averaged 95% in 2005, compared with 100% in 2004. The reduction in refinery utilization was primarily due to planned and unplanned maintenance in the second and fourth quarters of 2005.

Product Purchase Costs

The unfavourable impacts of lower refined product margins, lower volumes and lower refinery utilization were partially offset by lower third party refined product purchase costs in 2005 compared to 2004. Refined product purchase costs were higher in 2004 as a result of higher required purchased volumes of refined products to meet customer needs primarily due to a maintenance shutdown in 2004. Reduced third party purchase costs increased 2005 net earnings by $24 million.

Cash and Non-cash Operating Expenses

Overall, cash and non-cash operating expenses increased by $31 million after-tax in 2005 compared to 2004. Cash expenses increased by $20 million after-tax in 2005, primarily, due to higher energy and maintenance costs. Non-cash expenses increased by $3 million after-tax in 2005, due to increased depreciation as a result of a higher asset base. The higher 2005 expenses also reflect the absence of a 2004 mark-to-market gain of $8 million after-tax on inventory related derivatives.

Related Party Transactions

The Pioneer, UPI and SPC joint ventures 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)	**2005**	2004	2003
Operating revenues			
Sales to EM&R joint ventures:			
Refined products	**327**	320	301
Petrochemicals	**279**	272	187

At December 31, 2005, amounts due from EM&R joint ventures were $22 million, compared to $17 million at December 31, 2004.

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 of $11 million in 2005 compared to net earnings of $12 million in 2004 (2003 – $2 million after-tax loss).

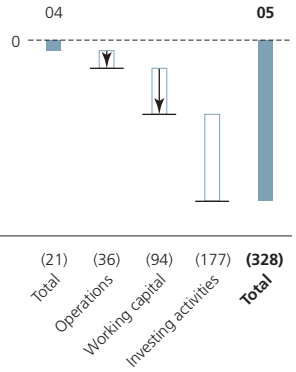
Energy trading activities, by their nature, can result in volatile and large positive or negative fluctuations in earnings. A separate risk management function reviews and monitors practices and policies and provides independent verification and valuation of these activities. See page 31.

Net Cash Deficiency Analysis

EM&R's net cash deficiency was $328 million in 2005 compared to a net cash deficiency of $21 million in 2004 (2003 – $29 million surplus). Cash flow from operations was $152 million in 2005 compared to $188 million in 2004 (2003 – $164 million). The decrease was due to the same factors impacting net earnings. Net working capital increased by $44 million in 2005, compared to a decrease of $50 million in 2004. The increase in net working capital is a result of decreases in taxes payable.

Cash used in investing activities was $436 million in 2005 compared to $259 million in 2004 (2003 – $135 million). The increase was primarily due to higher capital expenditures associated with the diesel desulphurization project at the Sarnia refinery, as well as increased refinery capital maintenance expenditures.

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



Outlook

In 2004, we began construction on a diesel desulphurization project at our Sarnia refinery to meet federal sulphur regulations that will be effective June 2006 and anticipated future federal sulphur regulations. Under the terms of an agreement with Shell Canada Products (Shell), the project facilities will also be used to process high-sulphur diesel from Shell's Sarnia refinery into low-sulphur diesel on a fee-for-service basis.

The project also includes capital expenditures to expand the refinery's throughput capacity and enable it to process approximately 40,000 bpd of Oil Sands sour crude blends. In order to facilitate this portion of the project, there is a planned 50-day maintenance shutdown scheduled for the fall of 2006. When all components are completed in 2007, we expect this project will cost a total of approximately $800 million.

Construction of an ethanol plant began in June 2005 and is expected to be completed in 2006. This facility is expected to produce ethanol at a capacity of 200 million litres per year for blending into Sunoco-branded and joint venture retail gasoline. The project is expected to cost $120 million, and is on schedule and on budget.

Including capital investment associated with diesel desulphurization and construction of the ethanol plant, EM&R expects total capital spending to be approximately $350 million in 2006.

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. The diesel desulphurization project must be completed prior to June 1, 2006, to ensure compliance with legislative requirements. 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, the new facilities for reducing sulphur in on-road diesel fuel should also allow the company to meet the requirements for reducing sulphur in off-road diesel and light fuel oil.

These factors and estimates are subject to certain risks, assumptions and uncertainties discussed on page 58 under Forward-looking Statements. Refer to the Suncor Overview, Risk Factors Affecting Performance on page 29.

R&M operates a 90,000 barrel per day (bpd) (approximately 14,300 cubic metre per day) capacity refining complex in Commerce City, Colorado and markets refined products to customers primarily in Colorado, including retail marketing through 43 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 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)	**2005**	2004	2003 (1)
Revenue	**2 621**	1 495	515
Refined product sales			
(millions of litres)			
Gasoline	**2 517**	1 627	636
Total	**5 004**	3 504	1 384
Net earnings	**142**	34	18
Cash flow from operations	**247**	59	34
Investing activities	**408**	198	300
Net cash surplus (deficiency)	**(121)**	(71)	(220)
ROCE (%) (2)	**49.4**	12.2	—
ROCE (%) (3)	**28.9**	11.0	—

(1) Reflects the results of operations since acquisition on August 1, 2003.

(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 56. For 2003, represents five months of operations since acquisition on August 1. Therefore no annual ROCE was calculated.

(3) Includes capitalized costs related to major projects in progress. See page 56.

2005 Overview

- On May 31, 2005, R&M acquired all of the issued shares of the Colorado Refining Company, an indirect wholly-owned subsidiary of Valero Energy Corporation for total cash consideration of $62 million, including additional associated price adjustments for purchased crude oil and product inventories. The acquired company's assets included a 30,000 bpd refinery in Commerce City, Colorado as well as a products terminal located in Grand Junction, Colorado.

- R&M continued construction on a project to modify the Commerce City refinery to allow it to meet regulations that take effect on June 1, 2006, requiring lower-sulphur diesel fuel. It is expected that modifications will also enable R&M to process 10,000 bpd to 15,000 bpd of Oil Sands sour crude while also increasing the refinery's ability to process a broader slate of bitumen-based crude oil. The capital budget for this project was increased to US$390 million (approximately Cdn$465 million) from the previous estimate of US$300 million (approximately Cdn$360 million) due to labour shortages and material supply issues.
- Approximately 6% of feedstock processed at the refinery was synthetic crude oil of which approximately half was supplied from our Oil Sands operations.

Analysis of Net Earnings

R&M's net earnings were $142 million in 2005 compared to $34 million in 2004 (2003 – $18 million). Earnings have increased due to higher refining margins, and higher average sales volumes, due in part to the acquisition of the Colorado Refining Company during 2005, as well as higher refinery utilization. The acquisition increased our U.S. refining capacity to 90,000 bpd from 60,000 bpd. These positive impacts were partially offset by higher product purchase costs and higher cash and non-cash refinery operating expenses.

Margins

Average refining margins were 9.0 cents per litre (cpl) in 2005 compared to 6.7 cpl in 2004 reflecting significantly higher gasoline and diesel margins, partially offset by lower net realizations on asphalt and other heavy product sales. Refined product margins were impacted by the reduced supply of light oil products following the hurricane activity in the Gulf of Mexico during the summer of 2005. Higher refined product margins in 2005 increased earnings by $220 million. Retail margins were 5.1 cpl in 2005, compared to 5.4 cpl in 2004 due to competitive pressures that resulted in narrowing of margins.

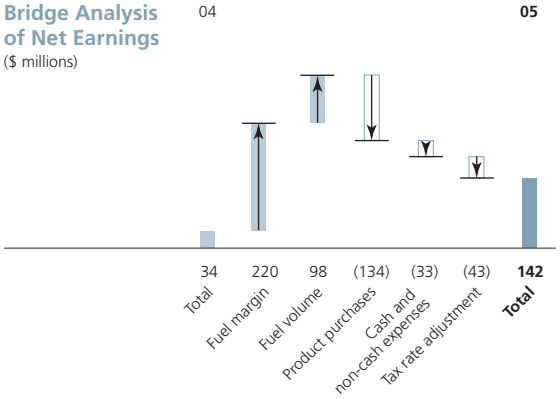
Volumes and Refinery Utilization

Sales volumes increased in 2005, primarily due to the acquisition of a second refinery, bringing total throughput capacity in the second half of the year to 90,000 bpd from 60,000 bpd. In addition, higher refinery utilization rates resulting from more reliable operations in 2005 resulted in an increase in net earnings of $98 million.

Refinery utilization was 98% in 2005 compared to 92% in 2004. Refinery utilization in the first half of 2004 was negatively impacted by a planned 19-day maintenance shutdown on certain refinery units, as well as operating difficulties that were rectified during the shutdown.

Partially offsetting the positive impacts of higher margins and volumes, increased product purchases reduced net earnings by $134 million. The higher volume of purchased refined products was primarily due to purchases of additional intermediate feedstock to facilitate higher refinery utilization rates, along with purchases of other finished products to meet customer demands.

Bridge Analysis of Net Earnings
($ millions)



Cash and Non-cash Expenses

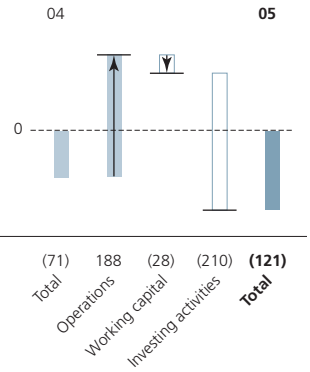
Increases in refinery cash expenses and non-cash depreciation, depletion and amortization were primarily due to incremental costs associated with the acquisition of the Colorado Refining Company as well as higher energy and maintenance related costs in 2005.

Net Cash Deficiency Analysis

R&M's net cash deficiency of $121 million in 2005 compared to a deficiency of $71 million in 2004 (2003 – $220 million deficiency). The increase in cash flow from operations to $247 million in 2005 from $59 million in 2004 (2003 – $34 million) was impacted by the same factors that affected net earnings. Net working capital decreased $40 million in 2005, compared to a decrease of $68 million in 2004 (2003 – $46 million decrease). The decrease in 2005 was primarily due to an increase in accounts payable related to capital expenditures on the refinery modifications, partially offset by an increase in accounts receivable and inventory as a result of higher product prices.

Cash used in investing activities was $408 million in 2005, compared to $198 million in 2004 (2003 – $300 million). Investing activities in 2005 were primarily related to costs associated with the refinery modification project, as well as the $62 million acquisition of Colorado Refining Company.

Bridge Analysis of Net Cash Deficiency
($ millions)



Outlook

R&M estimates spending approximately $225 million (approximately US$180 million) on capital project work in 2006. In 2006, we expect to complete modifications to the 60,000 bpd refinery acquired from ConocoPhillips (Commerce City west plant) to meet low-sulphur fuels regulations and expand the facility's capacity to process Oil Sands sour crude blends.

The refineries run a mixture of heavy and light crude oil feedstock from both Canadian and U.S. sources. In 2005, approximately 3% of R&M's crude slate came from Oil Sands. Suncor is currently assessing plans for additional refinery modifications post-2006 in order to have the potential to integrate up to an additional 30,000 bpd of Oil Sands crude oil. Cost estimates for this project are not yet available.

During the first quarter of 2006, scheduled maintenance is planned for pipeline and refinery equipment. During this estimated 42-day maintenance period, customer requirements are expected to be met from existing inventory, third party purchases and exchanges. This maintenance shutdown was originally scheduled to occur in the fourth quarter of 2005, but was postponed due to delays on the low-sulphur diesel project.

The United Steel Workers Union (USW) represents approximately 150 employees at R&M's Commerce City west plant. A contract extension was ratified in 2005 and will expire in January 2009. The same union represents approximately 87 employees at the east plant, acquired from Valero in May 2005. In February 2006, the east plant union voted to merge the east plant workers into the existing collective bargaining agreement at the west plant. The merged contract becomes effective in March 2006 and will expire in January 2009.

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.
- Certain risks associated with the execution of the fuels desulphurization project, including ensuring construction and commissioning is completed in time to comply with June 1, 2006 legislative requirements. Numerous risks and uncertainties can affect construction schedules, including the availability of labour, materials and other impacts of competing projects drawing on the same resources during the same time period. As well, our U.S. capital projects are expected to be partially funded from Canadian operations. A weaker Canadian dollar would result in a higher funding requirement for U.S. capital programs.

These factors and estimates are subject to certain risks, assumptions and uncertainties discussed on page 58 under Forward-looking Statements. Refer to the Suncor Overview, Risk Factors Affecting Performance on page 29.

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		**2005**	2004	2003
Cash flow from operations ($ millions)	A	**2 476**	2 013	2 040
Weighted average number of common shares outstanding (millions of shares)	B	**456**	453	450
Cash flow from operations (per share)	A/B	**5.43**	4.44	4.53

ROCE

For the year ended December 31 ($ millions, except ROCE)		**2005**	2004	2003
Adjusted net earnings				
Net earnings		**1 245**	1 088	1 087
Add: after-tax financing expenses (income)		**(16)**	1	(85)
	D	**1 229**	1 089	1 002
Capital employed – beginning of year				
Short-term and long-term debt, less cash and cash equivalents		**2 159**	2 577	3 204
Shareholders' equity		**4 921**	3 893	2 886
	E	**7 080**	6 470	6 090
Capital employed – end of year				
Short-term and long-term debt, less cash and cash equivalents		**2 891**	2 159	2 577
Shareholders' equity		**6 130**	4 921	3 893
	F	**9 021**	7 080	6 470
Average capital employed	(E+F)/2=G	**8 051**	6 775	6 280
Average capitalized costs related to major projects in progress (1)	H	**2 175**	1 030	817
ROCE (%)	D/(G-H)	**20.9**	19.0	18.3

(1) Prior to 2004, average capital employed was calculated using a simple average of opening and closing major projects in progress. In 2004 and 2005, we have used a quarterly average.

Oil Sands Operating Costs – Base Operations

(unaudited)		2005 (1) $ millions	2005 (1) $/barrel	2004 (2) $ millions	2004 (2) $/barrel	2003 $ millions	2003 $/barrel
Operating, selling and general expenses		**978**		871		865	
Less: natural gas costs and inventory changes		**(169)**		(142)		(176)	
Accretion of asset retirement obligations		**24**		21		21	
Taxes other than income taxes		**29**		28		24	
Cash costs		**862**	**14.95**	778	9.80	734	9.25
Natural gas		**216**	**3.75**	158	2.00	169	2.15
Imported bitumen (net of other reported product purchases)		**2**	**0.05**	13	0.15	4	0.05
Cash operating costs – in-situ operations		**150**	**2.60**	—	—	—	—
Less: Cost of in-situ production sold directly to market		**(107)**	**(1.85)**	—	—	—	—
Total cash operating costs – base operations	A	**1 123**	**19.50**	949	11.95	907	11.45
Start-up costs		**12**	**0.20**	26	0.35	10	0.10
Add: in-situ inventory changes		**—**		2	—	—	—
Less: pre-start-up commissioning costs		**(5)**	**(0.10)**	(4)	(0.05)	(10)	(0.10)
In-situ (Firebag) start-up costs	B	**7**	**0.10**	24	0.30	—	—
Total cash operating costs	A+B	**1 130**	**19.60**	973	12.25	907	11.45
Depreciation, depletion and amortization		**448**	**7.80**	484	6.10	458	5.80
Depreciation, depletion and amortization – in-situ operations		**34**	**0.60**	—	—	—	—
Less: Cost of in-situ production sold directly to market		**(24)**	**(0.40)**	—	—	—	—
Total operating costs		**1 588**	**27.60**	1 457	18.35	1 365	17.25
Production (thousands of barrels per day)		**157.6**		217.0		216.6	

Oil Sands Operating Costs – Firebag In-situ Bitumen Production

(unaudited)	2005 (1) $ millions	2005 (1) $/barrel	2004 (2) $ millions	2004 (2) $/barrel
Operating, selling and general expenses	**150**		68	
Less: natural gas costs and inventory changes	**(91)**		(39)	
Accretion of asset retirement obligations	**—**		—	
Taxes other than income taxes	**—**		—	
Cash costs	**59**	**8.45**	29	8.30
Natural gas	**91**	**13.05**	39	11.20
Cash operating costs	**150**	**21.50**	68	19.50
Depreciation, depletion and amortization	**34**	**4.90**	21	6.00
Total operating costs	**184**	**26.40**	89	25.50
Production (thousands of barrels per day)	**19.1**		12.7	

(1) Production in the base operations for the year ended December 31, 2005 includes upgraded Firebag in-situ volumes of 775 bpd produced in the fourth quarter of 2005 during the Firebag Stage 2 start-up period.

(2) Production in the base operations for the year ended December 31, 2004 includes upgraded Firebag in-situ volumes of 5,900 bpd produced in the first quarter of 2004 during the Firebag Stage 1 start-up period.

FORWARD-LOOKING STATEMENTS

This Management's Discussion and Analysis contains certain Forward-looking Statements that are based on our current expectations, estimates, projections and assumptions that were made in light of our experience and our perception of historical trends.

All statements that address expectations or projections about the future, including statements about our strategy for growth, expected and future expenditures, commodity prices, costs, schedules, production volumes, operating and financial results and expected impact of future commitments, are Forward-looking Statements. Some of the Forward-looking Statements may be identified by words like "expects," "future," "may," "slated," "strategy," "anticipates," "estimates," "plans," "intends," "believes," "projects," "indicates," "could," "focus," "vision," "goal," "proposed," "target," "objective," "expansion" and similar expressions. These statements are not guarantees of future performance and involve a number of risks and uncertainties, some of which are similar to other oil and gas companies and some of which are unique to us. Our actual results may differ materially from those expressed or implied by our 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 our products; commodity prices and currency exchange rates; logistical constraints to transport our product; our ability to respond to changing markets and to receive timely regulatory approvals; the successful and timely implementation of capital projects including growth projects (for example the Firebag in-situ development and Voyageur) and regulatory projects (for example, the clean fuels refinery modifications projects in our downstream businesses); the accuracy of cost estimates, some of which are provided at the conceptual or other preliminary stage of projects and prior to commencement or conception of the detailed engineering needed to reduce the margin of error or level of accuracy; the integrity and reliability of our 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 impact of weather conditions on our drilling program; the impact of material and labour shortages; the impact of market demand for land and services on capital and operating costs; the maintenance of satisfactory relationships with unions, employee associations and joint venture partners; competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternative sources of energy; the timing and amount of insurance proceeds received in connection with the January 2005 fire at the Oil Sands facility; uncertainties resulting from potential delays or changes in plans with respect to projects or capital expenditures; actions by governmental authorities including the imposition of taxes or changes to fees and royalties; changes in environmental and other regulations; the ability and willingness of parties with whom we have material relationships to perform their obligations; and the occurrence of unexpected events, blowouts, freeze-ups, equipment failures and other similar events affecting Suncor or other parties whose operations or assets directly or indirectly affect us. 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 our Annual Information Form/Form 40-F on file with Canadian securities commissions and the SEC. Readers are also referred to the risk factors described in other documents that we file from time to time with securities regulatory authorities. Copies of these documents are available without charge from Suncor.

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 61 to 97 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, will certify 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 61 to 65. 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

March 1, 2006

AUDITORS' REPORT

TO THE SHAREHOLDERS OF SUNCOR ENERGY INC.

We have audited the Consolidated Balance Sheets of Suncor Energy Inc. (the company) as at December 31, 2005 and 2004 and the Consolidated Statements of Earnings, Cash Flows and Changes in Shareholders' Equity for each of the years in the three year period ended December 31, 2005. 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 in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the company as at December 31, 2005 and 2004 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2005, in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta

March 1, 2006

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 change described in note 1 to the consolidated financial statements. Our report to the shareholders dated March 1, 2006 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

March 1, 2006

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 and petrochemical products, primarily in Ontario and Quebec. Petrochemical products are also sold in the United States and Europe.

Refining and Marketing – U.S.A. includes the manufacture, transportation and marketing of petroleum products, primarily in Colorado.

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. Revenues associated with multi-element arrangements are recognized on a straight-line basis over the term of associated services.

(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.

Other specific contractual obligations entered subsequent to January 1, 2005 have been treated as either capital or operating leases as required under Canadian reporting standards.

Gains and losses on the sale and leaseback of assets recorded as capital leases are deferred and amortized to earnings in proportion to the amortization of leased assets.

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.

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 overburden removal costs, deferred maintenance shutdown costs and deferred financing costs.

Overburden removal precedes the mining of the related oil sands deposit. Accordingly, the company employs a deferral method of accounting for overburden removal costs where all such costs are initially recorded as a deferred charge (see note 3), rather than expensing overburden removal costs as incurred. These deferred charges are allocated to the mining activity in the year on a last-in, first-out (LIFO) basis using stripping ratios based on a life of mine approach for each mine pit whereby all of the overburden to be removed is related to all of the oil sands proved and probable ore reserves. Amortization of deferred overburden removal cost is reported as part of the depreciation, depletion and amortization expense in the Consolidated Statements of Earnings. Stripping ratios are regularly reviewed to reflect changes in operating experience and other factors. See Recently Issued Canadian Accounting Standards, section (l) on page 65, for proposed changes to accounting for overburden.

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 in 2004 and subsequent fiscal years. 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 gain market information and to earn trading revenues. These energy marketing and trading activities are accounted for at fair value.

(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 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 exchange adjustments 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 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.

(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

Non-monetary Transactions

In 2005, the Canadian Institute of Chartered Accountants (CICA) approved Handbook section 3831 "Non-Monetary Transactions". Effective January 1, 2006, all non-monetary transactions must be measured at fair value (if determinable) unless the transaction lacks commercial substance, or is an exchange of a product held for sale in the ordinary course of business, or is a product to be sold in the same line of business. Commercial substance exists when the company's future cash flows are expected to change significantly as a result of a transaction. The company will be 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 will be recorded. The amount of the gross-up of revenues and purchases of crude oil and products will be dependent on the prevailing prices for natural gas. Currently the transaction is recorded net in purchases of crude oil and products. Retroactive adjustment is prohibited by the standard.

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.

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 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.

Overburden Removal Costs

On February 16, 2006, the Emerging Issues Committee of the CICA approved an abstract regarding the treatment of overburden costs in the mining industry effective July 1, 2006. The proposed abstract would require the capitalization of overburden removal costs when such costs represent betterment to the mine property by facilitating access to reserves in future periods. Costs are to be treated as variable production costs and expensed when no betterment exists. The company currently amortizes the cost of overburden removal using stripping ratios based on a life of mine approach. The company is considering expensing overburden costs incurred on a retroactive basis effective January 1, 2006. With the exception of the impact on 2005 net earnings, the effect of adopting the guidance is not expected to be significant. Net earnings in 2005 would be reduced by approximately $87 million due to increased amounts of overburden moved during the year.

CONSOLIDATED STATEMENTS OF EARNINGS

For the years ended December 31 ($ millions)	**2005**	2004	2003
Revenues			
Operating revenues (notes 6, 16 and 17)	**9 749**	8 270	6 329
Energy marketing and trading activities (note 6c)	**763**	392	276
Net insurance proceeds (note 10d)	**572**	—	—
Interest	**2**	3	6
	11 086	8 665	6 611
Expenses			
Purchases of crude oil and products	**4 184**	2 867	1 686
Operating, selling and general	**2 130**	1 769	1 478
Energy marketing and trading activities (note 6c)	**746**	373	279
Transportation and other costs	**152**	132	135
Depreciation, depletion and amortization	**720**	720	622
Accretion of asset retirement obligations	**30**	26	25
Exploration (note 17)	**56**	55	51
Royalties (note 4)	**555**	531	139
Taxes other than income taxes (note 17)	**529**	540	466
(Gain) on disposal of assets	**(13)**	(16)	(17)
Project start-up costs	**25**	26	16
Financing expenses (income) (note 14)	**(15)**	24	(74)
	9 099	7 047	4 806
Earnings Before Income Taxes	**1 987**	1 618	1 805
Provision for income taxes (note 9)			
Current	**39**	69	38
Future	**703**	461	680
	742	530	718
Net Earnings	**1 245**	1 088	1 087
Per Common Share (dollars) (note 12)			
Net earnings attributable to common shareholders			
Basic	**2.73**	2.40	2.42
Diluted	**2.67**	2.36	2.26
Cash dividends	**0.24**	0.23	0.1925

See accompanying Summary of Significant Accounting Policies and Notes.

CONSOLIDATED BALANCE SHEETS

As at December 31 ($ millions)	**2005**	2004
Assets		
Current assets		
Cash and cash equivalents	**165**	88
Accounts receivable (notes 10 and 17)	**1 139**	627
Inventories (note 15)	**523**	423
Income taxes receivable	**6**	—
Future income taxes (note 9)	**83**	57
Total current assets	**1 916**	1 195
Property, plant and equipment, net (note 2)	**12 966**	10 326
Deferred charges and other (note 3)	**469**	320
Total assets	**15 351**	11 841
Liabilities and Shareholders' Equity		
Current liabilities		
Short-term debt	**49**	30
Accounts payable and accrued liabilities (notes 7 and 8)	**1 830**	1 306
Income taxes payable	**—**	32
Taxes other than income taxes	**56**	41
Total current liabilities	**1 935**	1 409
Long-term debt (note 5)	**3 007**	2 217
Accrued liabilities and other (notes 7 and 8)	**1 005**	749
Future income taxes (note 9)	**3 274**	2 545
Total liabilities	**9 221**	6 920
Commitments and contingencies (note 10)		
Shareholders' equity		
Share capital (note 11)	**732**	651
Contributed surplus (note 11)	**50**	32
Cumulative foreign currency translation	**(81)**	(55)
Retained earnings	**5 429**	4 293
Total shareholders' equity	**6 130**	4 921
Total liabilities and shareholders' equity	**15 351**	11 841

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

March 1, 2006

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31 ($ millions)	**2005**	2004	2003
Operating Activities			
Cash flow from operations [(a)]	**2 476**	2 013	2 040
Decrease (increase) in operating working capital			
Accounts receivable	**(477)**	(121)	(105)
Inventories	**(63)**	(51)	(19)
Accounts payable and accrued liabilities	**508**	337	258
Taxes payable	**(23)**	16	5
Cash flow from operating activities	**2 421**	2 194	2 179
Cash Used in Investing Activities [(a)]	**(3 186)**	(1 825)	(1 708)
Net Cash Surplus (Deficiency) Before Financing Activities	**(765)**	369	471
Financing Activities			
Increase (decrease) in short-term debt	**19**	(1)	31
Proceeds from issuance of long-term debt	**—**	—	651
Net increase (decrease) in other long-term debt	**808**	(635)	(716)
Issuance of common shares under stock option plans	**69**	41	20
Dividends paid on common shares	**(102)**	(97)	(81)
Deferred revenue	**50**	26	—
Cash flow provided by (used in) financing activities	**844**	(666)	(95)
Increase (Decrease) in Cash and Cash Equivalents	**79**	(297)	376
Effect of Foreign Exchange on Cash and Cash Equivalents	**(2)**	(3)	(3)
Cash and Cash Equivalents at Beginning of Year	**88**	388	15
Cash and Cash Equivalents at End of Year	**165**	88	388

(a) See Schedules of Segmented Data on pages 72 and 73.

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, 2002, as previously reported	578	—	—	2 296
Retroactive adjustment for change in accounting policy, net of tax (note 1)	—	—	—	12
At December 31, 2002, as restated	578	—	—	2 308
Net earnings	—	—	—	1 087
Dividends paid on common shares	—	—	—	(81)
Issued for cash under stock option plans	20	—	—	—
Issued under dividend reinvestment plan	6	—	—	(6)
Stock-based compensation expense	—	7	—	—
Foreign currency translation adjustment	—	—	(26)	—
At December 31, 2003, as restated	604	7	(26)	3 308
Net earnings	—	—	—	1 088
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)**	**4 293**
Net earnings	**—**	**—**	**—**	**1 245**
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	**732**	**50**	**(81)**	**5 429**

See accompanying Summary of Significant Accounting Policies and Notes.

SCHEDULES OF SEGMENTED DATA [a]

For the years ended December 31 ($ millions)	Oil Sands 2005	Oil Sands 2004	Oil Sands 2003	Natural Gas 2005	Natural Gas 2004	Natural Gas 2003	Energy Marketing and Refining – Canada 2005	Energy Marketing and Refining – Canada 2004	Energy Marketing and Refining – Canada 2003
EARNINGS									
Revenues [b]									
Operating revenues	**2 938**	3 215	2 716	**653**	499	436	**3 536**	3 060	2 660
Energy marketing and trading activities	**—**	—	—	**—**	—	—	**763**	400	276
Net insurance proceeds (note 10d)	**572**	—	—	**—**	—	—	**—**	—	—
Intersegment revenues [c]	**455**	425	385	**26**	68	76	**—**	—	—
Interest	**—**	—	—	**—**	—	—	**—**	—	—
	3 965	3 640	3 101	**679**	567	512	**4 299**	3 460	2 936
Expenses									
Purchases of crude oil and products	**32**	75	12	**—**	—	—	**2 585**	2 115	1 797
Operating, selling and general	**1 128**	939	865	**93**	100	73	**484**	418	359
Energy marketing and trading activities	**—**	—	—	**—**	—	—	**746**	381	279
Transportation and other costs	**104**	88	101	**22**	21	24	**6**	3	3
Depreciation, depletion and amortization	**482**	505	459	**130**	115	91	**73**	69	59
Accretion of asset retirement obligations	**24**	21	21	**5**	4	3	**1**	1	1
Exploration	**10**	17	11	**46**	38	40	**—**	—	—
Royalties (note 4)	**406**	407	33	**149**	124	106	**—**	—	—
Taxes other than income taxes	**51**	72	64	**3**	2	3	**338**	352	342
(Gain) loss on disposal of assets	**—**	4	(1)	**(12)**	(19)	(12)	**(1)**	(2)	(4)
Project start-up costs	**25**	26	10	**—**	—	—	**—**	—	—
Financing expenses (income)	**—**	—	—	**—**	—	—	**—**	—	—
	2 262	2 154	1 575	**436**	385	328	**4 232**	3 337	2 836
Earnings (loss) before income taxes	**1 703**	1 486	1 526	**243**	182	184	**67**	123	100
Income taxes	**(630)**	(492)	(639)	**(88)**	(67)	(64)	**(26)**	(43)	(47)
Net earnings (loss)	**1 073**	994	887	**155**	115	120	**41**	80	53
As at December 31									
TOTAL ASSETS	**11 850**	9 067	7 970	**1 307**	967	765	**1 955**	1 321	1 080

(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 2005, 2004 or 2003 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. 2005	2004	2003	Corporate and Eliminations 2005	2004	2003	Total 2005	2004	2003
EARNINGS									
Revenues [b]									
Operating revenues	**2 619**	1 494	515	**3**	2	2	**9 749**	8 270	6 329
Energy marketing and trading activities	**—**	—	—	**—**	(8)	—	**763**	392	276
Net insurance proceeds (note 10d)	**—**	—	—	**—**	—	—	**572**	—	—
Intersegment revenues [c]	**—**	—	—	**(481)**	(493)	(461)	**—**	—	—
Interest	**2**	1	—	**—**	2	6	**2**	3	6
	2 621	1 495	515	**(478)**	(497)	(453)	**11 086**	8 665	6 611
Expenses									
Purchases of crude oil and products	**2 048**	1 171	340	**(481)**	(494)	(463)	**4 184**	2 867	1 686
Operating, selling and general	**167**	124	68	**258**	188	113	**2 130**	1 769	1 478
Energy marketing and trading activities	**—**	—	—	**—**	(8)	—	**746**	373	279
Transportation and other costs	**20**	20	7	**—**	—	—	**152**	132	135
Depreciation, depletion and amortization	**23**	22	6	**12**	9	7	**720**	720	622
Accretion of asset retirement obligations	**—**	—	—	**—**	—	—	**30**	26	25
Exploration	**—**	—	—	**—**	—	—	**56**	55	51
Royalties (note 4)	**—**	—	—	**—**	—	—	**555**	531	139
Taxes other than income taxes	**137**	114	57	**—**	—	—	**529**	540	466
(Gain) loss on disposal of assets	**—**	1	—	**—**	—	—	**(13)**	(16)	(17)
Project start-up costs	**—**	—	6	**—**	—	—	**25**	26	16
Financing expenses (income)	**—**	—	—	**(15)**	24	(74)	**(15)**	24	(74)
	2 395	1 452	484	**(226)**	(281)	(417)	**9 099**	7 047	4 806
Earnings (loss) before income taxes	**226**	43	31	**(252)**	(216)	(36)	**1 987**	1 618	1 805
Income taxes	**(84)**	(9)	(13)	**86**	81	45	**(742)**	(530)	(718)
Net earnings (loss)	**142**	34	18	**(166)**	(135)	9	**1 245**	1 088	1 087
As at December 31									
TOTAL ASSETS	**1 235**	518	442	**(996)**	(32)	283	**15 351**	11 841	10 540

SCHEDULES OF SEGMENTED DATA [a] (continued)

For the years ended December 31 ($ millions)	Oil Sands 2005	Oil Sands 2004	Oil Sands 2003	Natural Gas 2005	Natural Gas 2004	Natural Gas 2003	Energy Marketing and Refining – Canada 2005	Energy Marketing and Refining – Canada 2004	Energy Marketing and Refining – Canada 2003
CASH FLOW BEFORE FINANCING ACTIVITIES									
Cash from (used in) operating activities:									
Cash flow from (used in) operations									
Net earnings (loss)	**1 073**	994	887	**155**	115	120	**41**	80	53
Exploration expenses	**—**	—	—	**46**	38	40	**—**	—	—
Non-cash items included in earnings									
Depreciation, depletion and amortization	**482**	505	459	**130**	115	91	**73**	69	59
Income taxes	**630**	492	639	**88**	67	64	**26**	43	47
(Gain) loss on disposal of assets	**—**	4	(1)	**(12)**	(19)	(12)	**(1)**	(2)	(4)
Stock-based compensation expense	**—**	—	—	**—**	—	—	**—**	—	—
Other	**11**	(29)	4	**5**	4	(5)	**13**	(3)	10
Overburden removal outlays	**(287)**	(222)	(175)	**—**	—	—	**—**	—	—
Increase (decrease) in deferred credits and other	**(14)**	8	(10)	**—**	(1)	—	**—**	1	(1)
Total cash flow from (used in) operations	**1 895**	1 752	1 803	**412**	319	298	**152**	188	164
Decrease (increase) in operating working capital	**(223)**	72	56	**(5)**	(1)	12	**(44)**	50	—
Total cash from (used in) operating activities	**1 672**	1 824	1 859	**407**	318	310	**108**	238	164
Cash from (used in) investing activities:									
Capital and exploration expenditures	**(1 948)**	(1 119)	(953)	**(363)**	(279)	(184)	**(442)**	(228)	(122)
Acquisition of Denver refineries and related assets	**—**	—	—	**—**	—	—	**—**	—	—
Proceeds from property loss	**44**	—	—	**—**	—	—	**—**	—	—
Deferred maintenance shutdown expenditures	**(65)**	(4)	(100)	**(2)**	(1)	—	**—**	(20)	(17)
Deferred outlays and other investments	**(1)**	(9)	(10)	**—**	—	—	**3**	(14)	(2)
Proceeds from disposals	**41**	45	3	**21**	29	17	**3**	3	6
Total cash (used in) investing activities	**(1 929)**	(1 087)	(1 060)	**(344)**	(251)	(167)	**(436)**	(259)	(135)
Net cash surplus (deficiency) before financing activities	**(257)**	737	799	**63**	67	143	**(328)**	(21)	29

(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. 2005	2004	2003	Corporate and Eliminations 2005	2004	2003	Total 2005	2004	2003
CASH FLOW BEFORE FINANCING ACTIVITIES									
Cash from (used in) operating activities:									
Cash flow from (used in) operations									
Net earnings (loss)	**142**	34	18	**(166)**	(135)	9	**1 245**	1 088	1 087
Exploration expenses	**—**	—	—	**—**	—	—	**46**	38	40
Non-cash items included in earnings									
Depreciation, depletion and amortization	**23**	22	6	**12**	9	7	**720**	720	622
Income taxes	**84**	9	13	**(125)**	(150)	(83)	**703**	461	680
(Gain) loss on disposal of assets	**—**	1	—	**—**	—	—	**(13)**	(16)	(17)
Stock-based compensation expense	**—**	—	—	**23**	25	7	**23**	25	7
Other	**(2)**	(8)	(2)	**(60)**	(71)	(210)	**(33)**	(107)	(203)
Overburden removal outlays	**—**	—	—	**—**	—	—	**(287)**	(222)	(175)
Increase (decrease) in deferred credits and other	**—**	1	(1)	**86**	17	11	**72**	26	(1)
Total cash flow from (used in) operations	**247**	59	34	**(230)**	(305)	(259)	**2 476**	2 013	2 040
Decrease (increase) in operating working capital	**40**	68	46	**177**	(8)	25	**(55)**	181	139
Total cash from (used in) operating activities	**287**	127	80	**(53)**	(313)	(234)	**2 421**	2 194	2 179
Cash from (used in) investing activities:									
Capital and exploration expenditures	**(337)**	(190)	(31)	**(63)**	(31)	(32)	**(3 153)**	(1 847)	(1 322)
Acquisition of Denver refineries and related assets	**(62)**	—	(272)	**—**	—	—	**(62)**	—	(272)
Proceeds from property loss	**—**	—	—	**—**	—	—	**44**	—	—
Deferred maintenance shutdown expenditures	**(10)**	(7)	—	**—**	—	—	**(77)**	(32)	(117)
Deferred outlays and other investments	**1**	(1)	3	**(6)**	1	(14)	**(3)**	(23)	(23)
Proceeds from disposals	**—**	—	—	**—**	—	—	**65**	77	26
Total cash (used in) investing activities	**(408)**	(198)	(300)	**(69)**	(30)	(46)	**(3 186)**	(1 825)	(1 708)
Net cash surplus (deficiency) before financing activities	**(121)**	(71)	(220)	**(122)**	(343)	(280)	**(765)**	369	471

1. CHANGE IN ACCOUNTING POLICY

(a) Preferred Securities

On January 1, 2005, the company retroactively adopted the Canadian accounting standard related to disclosure and presentation of financial instruments. Accordingly, the company's preferred securities, which were redeemed in March 2004, have been reclassified as long-term debt, and the preferred dividend payments have been reclassified to financing expense. The company has restated its property, plant and equipment and depreciation, depletion and amortization to reflect capitalized interest that would have been incurred and amortized had the preferred securities been classified as debt during the period in which they were outstanding. The impact of adopting this accounting standard is as follows:

Change in Consolidated Balance Sheets

($ millions, increase)	**2005**	2004
Property, plant and equipment	**35**	37
Total assets	**35**	37
Future income tax liabilities	**12**	13
Retained earnings	**23**	24
Total liabilities and shareholders' equity	**35**	37

Change in Consolidated Statements of Earnings

($ millions, increase/(decrease))	**2005**	2004	2003
Depreciation, depletion and amortization	**2**	3	4
Financing expenses	**—**	15	(8)
Future income taxes	**(1)**	(6)	(8)
Net earnings (loss)	**(1)**	(12)	12
Per common share – basic (dollars)	**—**	—	—
Per common share – diluted (dollars)	**—**	—	—

(b) Consolidation of Variable Interest Entities

On January 1, 2005 the company prospectively adopted Canadian Accounting Guideline 15 – "Consolidation of Variable Interest Entities"(VIEs). Accordingly, the company has consolidated the VIE related to the sale of equipment as described in note 10c. The impact of adopting this standard was an increase to property, plant and equipment of $14 million, an increase to materials and supplies inventory of $8 million and an increase to long-term debt of $22 million. There was no impact to net earnings.

2. PROPERTY, PLANT AND EQUIPMENT

($ millions)	2005 Cost	2005 Accumulated Provision	2004 Cost	2004 Accumulated Provision
Oil Sands				
Plant	**5 644**	**1 107**	5 197	935
Mine and mobile equipment	**1 358**	**561**	1 313	480
In-situ properties	**1 610**	**60**	1 267	26
Pipeline	**107**	**50**	101	48
Capital leases	**39**	**5**	29	25
Major projects in progress	**2 484**	**—**	1 486	—
Asset retirement cost	**408**	**81**	325	71
	11 650	**1 864**	9 718	1 585
Natural Gas				
Proved properties	**1 632**	**769**	1 387	652
Unproved properties	**172**	**23**	125	18
Other support facilities and equipment	**53**	**13**	28	14
Asset retirement cost	**14**	**6**	27	3
	1 871	**811**	1 567	687
Energy Marketing and Refining – Canada				
Refinery	**899**	**481**	875	468
Marketing	**597**	**244**	525	248
Major projects in progress	**464**	**—**	171	—
Asset retirement cost	**11**	**7**	11	5
	1 971	**732**	1 582	721
Refining and Marketing – U.S.A.				
Refinery and intangible assets	**244**	**24**	175	11
Marketing	**36**	**3**	38	2
Pipeline	**26**	**2**	25	1
Major projects in progress	**453**	**—**	128	—
	759	**29**	366	14
Corporate	**180**	**29**	118	18
	16 431	**3 465**	13 351	3 025
Net property, plant and equipment		**12 966**		10 326

3. DEFERRED CHARGES AND OTHER

($ millions)	2005	2004
Oil Sands overburden removal costs (see below)	**202**	67
Deferred maintenance shutdown costs	**160**	129
Deferred financing costs	**23**	25
Other	**84**	99
Total deferred charges and other	**469**	320
Oil Sands overburden removal costs		
Balance – beginning of year	**67**	51
Outlays during the year	**287**	222
Depreciation on equipment during year	**26**	19
	380	292
Amortization during year	**(178)**	(225)
Balance – end of year	**202**	67

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 being treated by the Government of Alberta as a separate project from the rest of the Oil Sands operations for royalty purposes. During 2004 and 2005, 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.

Royalty expense for the company's Oil Sands operations for the year ended December 31, 2005 was $406 million (2004 – $407 million, 2003 – $33 million).

In July 2004, we issued a statement of claim against the Crown, seeking, among other things, to overturn the government's decision on the royalty treatment of our Firebag in-situ operations. In February 2006, we advised the Government of Alberta that we had elected not to proceed with our claim relating to the royalty treatment of Firebag.

5. LONG-TERM DEBT

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

($ millions)	**2005**	2004
5.95% Notes, denominated in U.S. dollars, due in 2034 (US$500)	**583**	602
7.15% Notes, denominated in U.S. dollars, due in 2032 (US$500)	**583**	602
6.70% Series 2 Medium Term Notes, due in 2011 [(a)]	**500**	500
6.80% Medium Term Notes, due in 2007 [(a)]	**250**	250
6.10% Medium Term Notes, due in 2007 [(a)]	**150**	150
	2 066	2 104
Revolving-term debt, with interest at variable rates (see B. Credit Facilities)		
Commercial paper (interest at December 31, 2005 – 3.2%, 2004 – 2.3%) [(b)]	**890**	89
Total unsecured long-term debt	**2 956**	2 193
Secured long-term debt with interest rates averaging 5.2% (2004 – 5.4%)	**1**	5
Capital leases [(c), (d)]	**30**	19
Variable interest entity long-term debt – see note 1(b)	**20**	—
Total long-term debt	**3 007**	2 217

(a) 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	2005 Effective Interest Rate	2004 Effective Interest Rate
Swap of 6.70% Medium Term Notes to floating rates	200	2011	4.0%	3.5%
Swap of 6.80% Medium Term Notes to floating rates	250	2007	4.6%	4.3%
Swap of 6.10% Medium Term Notes to floating rates	150	2007	4.0%	3.6%

(b) 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).

(c) Obligations under capital leases are as follows:

($ millions)	**2005**	2004
Equipment leases with interest rates between prime plus 0.5% and 12.4% and maturing on dates ranging from 2008 and 2035	**30**	19
	30	19

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

($ millions)	Capital Leases	Other Long-term Debt
2006	3	910
2007	3	401
2008	3	—
2009	3	—
2010	3	—
Later years	71	1 666
Total minimum payments	86	2 977
Less amount representing imputed interest	56	
Present value of obligation under capital leases	30	

Long-term Debt (per cent)	**2005**	2004
Variable rate	**50**	31
Fixed rate	**50**	69

B. Credit Facilities

At December 31, 2005, the company had available credit and term loan facilities of $2,330 million, of which $1,255 million was undrawn, as follows:

($ millions)	
Facility that is fully revolving for 364 days and expires in 2006	600
Facility that is fully revolving for 364 days, has a term period of one year and expires in 2007	200
Facility that is fully revolving for a period of three years and expires in 2007	1 500
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	1 075
Total undrawn credit facilities	1 255

At December 31, 2005, the company had issued $185 million (2004 – $131 million) in letters of credit to various third parties.

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 next page 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:

	2005		2004	
($ millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	**165**	**165**	88	88
Accounts receivable	**1 139**	**1 139**	627	627
Current liabilities	**1 826**	**1 826**	1 252	1 252
Long-term debt				
Fixed-term	**2 066**	**2 299**	2 104	2 339
Revolving-term	**890**	**890**	89	89
Other	**21**	**21**	5	5
Capital leases	**30**	**30**	19	19

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 U.S. dollar West Texas Intermediate (WTI) derivative transactions. During 2005, the company resumed its strategic crude oil hedging program, fixing a price or range of prices for a percentage of total production of crude oil for specified periods of time. During 2005, the company entered into agreements covering 7,000 barrels per day (bpd) beginning January 1, 2006 and ending December 31, 2007. Prices for these barrels are fixed within a range of US$50.00 per barrel to an average of US$92.57 per barrel WTI. The company has not hedged any portion of the foreign exchange component of these forecasted cash flows.

At December 31, 2005, 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 2006 and 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 option 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, 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
As at December 31, 2003				
Crude oil swaps	68 000	24	772	2004
Costless collars	11 000	21 – 24	109 – 125	2004
Crude oil swaps	36 000	23	390	2005

Natural Gas	Quantity (GJ/day)	Average Price (Cdn$/GJ)	Revenue Hedged (Cdn$ millions)	Hedge Period[c]
As at December 31, 2005				
Swaps	**4 000**	**6.58**	**10**	**2006**
Costless collars	**25 000**	**10.76 – 16.13**	**24 – 36**	**2006**[g]
Costless collars	**10 000**	**8.75 – 13.38**	**19 – 29**	**2006**[h]
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[i]
As at December 31, 2003	30 000	6	16	2004[j]

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, 2005	**5 100**	**11.69**	**10**	**2006**[d]
As at December 31, 2004	6 300	7	15	2005[e]
As at December 31, 2003	6 600	5	3	2004[f]

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

(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 May 2006, inclusive.
(e) For the period January to September 2005, inclusive.
(f) For the period January and February 2004.
(g) For the period January to March 2006, inclusive.
(h) For the period April to October 2006, inclusive.
(i) For the period January to March 2005, inclusive.
(j) For the period January to March 2004, inclusive.
(k) Settlement for applicable forward is March 2006.
(l) Settlements for applicable forwards occurring within the period April to September 2007.

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, 2005 are detailed in note 5, Long-term debt.

Fair Value of 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)	**2005**	2004
Revenue hedge swaps and collars	**(4)**	(305)
Margin hedge swaps	**1**	5
Interest rate swaps and foreign currency forwards	**22**	36
Fair value of outstanding hedging derivative financial instruments	**19**	(264)

(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 gain market information and earn trading and marketing revenues. These energy trading activities are accounted for using the mark-to-market method and as such all financial instruments are recorded at fair value at each balance sheet date. The results of these activities are reported as revenue and as energy trading and marketing expenses in the Consolidated Statements of Earnings.

Physical energy marketing contracts involve activities intended to enhance prices and satisfy physical deliveries to customers. For the year ended December 31, 2005 physical energy marketing contracts resulted in a net pretax gain of $15 million (2004 – pretax gain of $12 million; 2003 – pretax gain of $2 million).

The company also enters into various financial energy contracts for trading activities. The following information presents all positions for the financial instruments only. For the year ended December 31, 2005, a net pretax gain of $5 million (2004 – pretax gain $11 million; 2003 – pretax loss of $3 million) resulted from the settlement and revaluation of the financial energy contracts. The above amounts do not include the impact of related general and administrative costs.

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

($ millions)	**2005**	2004
Energy trading assets	**82**	26
Energy trading liabilities	**70**	9
Net energy trading assets	**12**	17

Change in fair value of net assets

($ millions)	**2005**
Fair value of contracts at December 31, 2004	17
Changes in values attributable to market price and other market changes	**(108)**
Fair value of contracts entered into during the period	**115**
Fair value of contracts realized during 2005	**(12)**
Fair value of contracts outstanding at December 31, 2005	**12**

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)	**2005**	2004
Derivative contracts not accounted for as hedges	**82**	7
Unrecognized derivative contracts accounted for as a hedge	**30**	21
Total	**112**	28

7. ACCRUED LIABILITIES AND OTHER

($ millions)	**2005**	2004
Asset retirement obligations [(a)]	**489**	429
Employee future benefits liability (see note 8)	**190**	183
Employee and director incentive plans	**110**	50
Deferred revenue	**140**	64
Environmental remediation costs [(b)]	**33**	8
Other	**43**	15
Total	**1 005**	749

(a) Asset Retirement Obligations

The asset retirement obligation (ARO) also includes $54 million in current liabilities (2004 – $47 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)	**2005**	2004
Asset retirement obligations, beginning of year	**476**	401
Liabilities incurred	**71**	82
Liabilities settled	**(34)**	(33)
Accretion of asset retirement obligations	**30**	26
Asset retirement obligations, end of year	**543**	476

The total undiscounted amount of estimated cash flows required to settle the obligations at December 31, 2005 was approximately $1.2 billion (2004 – $1.1 billion). The liability recognized in 2005 has been discounted using a credit-adjusted risk-free rate of 5.6% (2004 – 6.0%). Payments to settle the ARO occur on an ongoing basis and will continue over the lives of the operating assets, which can exceed 35 years.

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 will be recorded in the first period in which the lives of the assets are determinable.

(b) Environmental Remediation Costs

Total accrued environmental remediation costs include an additional $14 million in current liabilities (2004 – $35 million). Environmental remediation costs include obligations assumed through the purchase of the Commerce City refineries. There is no associated asset retirement obligation for these assets as the assets have an indeterminate life.

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, 2005 was $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 senior executive retirement plan on a voluntary basis. The amount and timing of future funding for these supplementary plans is subject to capital availability and is at the company's discretion. At the end of December 2005, ***Plan Assets*** *to meet the* ***Benefit Obligation*** *were $479 million.*

The excess of the ***Benefit Obligation*** *over* ***Plan Assets*** *of $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 a pension committee on behalf of beneficiaries. The committee retains independent managers and advisors.

Funding of the registered retirement plans complies with applicable regulations that require actuarial valuations of the pension funds at least once every three years in Canada, depending on funding status, and every year in the United States. The most recent valuation for the Canadian plan was performed in 2004.

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

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

Obligations and Funded Status

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

($ millions)	Pension Benefits 2005	Pension Benefits 2004	Other Post-retirement Benefits 2005	Other Post-retirement Benefits 2004
Change in benefit obligation				
Benefit obligation at beginning of year	**624**	568	**128**	117
Service costs	**32**	25	**5**	5
Interest costs	**38**	34	**6**	7
Plan participants' contributions	**3**	3	**—**	—
Acquisition [(a)]	**1**	—	**1**	—
Foreign exchange	**—**	(2)	**—**	(1)
Actuarial loss	**75**	21	**8**	4
Benefits paid	**(28)**	(25)	**(4)**	(4)
Benefit obligation at end of year [(b), (e)]	**745**	624	**144**	128
Change in plan assets [(c)]				
Fair value of plan assets at beginning of year	**399**	336	**—**	—
Actual return on plan assets	**41**	33	**—**	—
Employer contributions	**61**	49	**—**	—
Plan participants' contributions	**3**	3	**—**	—
Benefits paid	**(25)**	(22)	**—**	—
Fair value of plan assets at end of year [(e)]	**479**	399	**—**	—
Net unfunded obligation	**(266)**	(225)	**(144)**	(128)
Items not yet recognized in earnings:				
Unamortized net actuarial loss [(d)]	**167**	125	**53**	49
Unamortized past service costs	**—**	—	**(26)**	(29)
Accrued benefit liability	**(99)**	(100)	**(117)**	(108)
Current liability	**(37)**	(40)	**(3)**	(3)
Long-term liability	**(76)**	(78)	**(114)**	(105)
Long-term asset	**14**	18	**—**	—
Total accrued benefit liability	**(99)**	(100)	**(117)**	(108)

(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 2005	Pension Benefit Obligations 2004	Other Post-retirement Benefits Obligation 2005	Other Post-retirement Benefits Obligation 2004
Discount rate	**5.00**	5.75	**5.00**	5.75
Rate of compensation increase	**4.50**	4.50	**4.25**	4.25

A one per cent 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	(4)	4	(15)	17	7	(7)
Increase (decrease) to benefit obligation	—	—	(119)	140	35	(33)

In order to measure the expected cost of other post-retirement benefits, a 10% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2005 (2004 – 11.5%; 2003 – 12%). 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 have a significant effect on the amounts reported for other post-retirement benefit obligations. A one per cent 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	13	(11)

(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 (2004 and 2003 – 12 years), and over the expected average future service life to full eligibility age of 9 years for other post-retirement benefits (2004 and 2003 – 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)	**2005**	2004	**2005**	2004
Partially funded plans	**745**	537	**—**	—
Unfunded plans	—	87	**144**	128
Benefit obligation at end of year	**745**	624	**144**	128

Components of Net Periodic Benefit Cost [(a)]

	Pension Benefits			Other Post-retirement Benefits		
($ millions)	**2005**	2004	2003	**2005**	2004	2003
Current service costs	**32**	25	18	**5**	5	3
Interest costs	**38**	34	32	**6**	7	6
Expected return on plan assets [(b)]	**(28)**	(25)	(20)	**—**	—	—
Amortization of net actuarial loss	**21**	19	22	**1**	1	1
Net periodic benefit cost recognized [(c)]	**63**	53	52	**12**	13	10

Components of Net Incurred Benefit Cost [(a)]

	Pension Benefits			Other Post-retirement Benefits		
($ millions)	**2005**	2004	2003	**2005**	2004	2003
Current service costs	**32**	25	18	**5**	5	3
Interest costs	**38**	34	32	**6**	7	6
Actual (return) loss on plan assets [(b)]	**(41)**	(33)	(45)	**—**	—	—
Actuarial (gain) loss	**75**	21	37	**8**	4	8
Net incurred benefit cost	**104**	47	42	**19**	16	17

(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)	**2005**	2004	2003	**2005**	2004	2003
Discount rate	**5.75**	6.00	6.50	**5.75**	6.00	6.50
Expected return on plan assets	**6.75**	7.00	7.25	**—**	—	—
Rate of compensation increase	**4.50**	4.00	4.00	**4.25**	4.00	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, 2005 and 2004, and the target allocation for 2006 are as follows:

	Target Allocation %	Percentage of Plan Assets	
	2006	**2005**	2004
Asset Category			
Equities	60	**60**	60
Fixed income	40	**40**	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 2006 will be $64 million, including approximately $12 million for the company's senior executive and supplemental retirement plans. Expected benefit payments from all of our plans are as follows:

	Pension Benefits	Other Post-retirement Benefits
2006	29	4
2007	31	5
2008	33	5
2009	35	6
2010	37	6
2011 – 2015	227	39
Total	392	65

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 $10 million in 2005 (2004 – $8 million; 2003 – $6 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:

	2005		2004		2003	
($ millions)	Amount	%	Amount	%	Amount	%
Federal tax rate	**696**	**35**	582	36	668	37
Provincial abatement	**(199)**	**(10)**	(162)	(10)	(181)	(10)
Federal surtax	**22**	**1**	18	1	20	1
Provincial tax rates	**229**	**12**	190	12	226	13
Statutory tax and rate	**748**	**38**	628	39	733	41
Adjustment of statutory rate for future rate reductions	**(88)**	**(5)**	(86)	(5)	(100)	(6)
	660	**33**	542	34	633	35
Add (deduct) the tax effect of:						
Crown royalties	**119**	**6**	133	8	50	3
Resource allowance [(a)]	**(48)**	**(2)**	(69)	(4)	(31)	(2)
Large corporations tax	**23**	**1**	18	1	19	1
Tax rate changes on opening future income taxes [(b)]	**—**	**—**	(53)	(3)	89	5
Attributed Canadian royalty income	**(24)**	**(1)**	(29)	(2)	(8)	—
Stock-based compensation	**8**	**—**	8	—	3	—
Assessments and adjustments	**7**	**—**	—	—	—	—
Capital gains	**(6)**	**—**	(18)	(1)	(34)	(2)
Other	**3**	**—**	(2)	—	(3)	—
Income taxes and effective rate	**742**	**37**	530	33	718	40

(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) Effective January 1, 2003, the Canadian government enacted changes to the federal taxation policies relating to the resource sector. The changes are to be fully phased in by 2007 and include a 7% reduction of the federal rate, deductibility of provincial Crown royalties and the elimination of the federal resource allowance deduction. In 2005 and 2004, the company's future income tax liabilities related to its resource operations were based on the future tax rates with the full 7% federal tax rate reduction.

In 2005 net income tax payments totalled $77 million (2004 – $50 million payment; 2003 – $45 million payment).

Effective April 1, 2004, the Alberta provincial corporate tax rate decreased by 1% (2003 – decrease of 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 (2003 – an increase of $89 million).

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

	2005		2004	
($ millions)	Current	Non-current	Current	Non-current
Future income tax assets:				
Employee future benefits	**7**	**—**	14	—
Asset retirement obligations	**19**	**—**	16	—
Inventories	**67**	**—**	27	—
Other	**(10)**	**—**	—	—
	83	**—**	57	—
Future income tax liabilities:				
Depreciation	**—**	**3 294**	—	2 747
Overburden removal costs	**—**	**68**	—	20
Deferred maintenance shutdown costs	**—**	**51**	—	44
Reorganization adjustment	**—**	**197**	—	—
Employee future benefits	**—**	**(87)**	—	(77)
Asset retirement obligations	**—**	**(162)**	—	(139)
Attributed Canadian royalty income	**—**	**(86)**	—	(69)
Other	**—**	**(1)**	—	19
	—	**3 274**	—	2 545

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

(a) Operating Commitments

In order to ensure continued availability of, and access to, facilities and services to meet its operational requirements, the company periodically enters into transportation service agreements for pipeline capacity and energy services agreements as well as non-cancellable operating leases for service stations, office space and other property and equipment. Under contracts existing at December 31, 2005, future minimum amounts payable under these leases and agreements are as follows:

($ millions)	Pipeline Capacity and Energy Services (1)	Operating Leases
2006	222	36
2007	216	32
2008	232	27
2009	242	22
2010	245	20
Later years	4 018	96
	5 175	233

(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 primary and excess property loss and business interruption insurance policies with a combined coverage limit of up to US$1,150 million, net of deductible amounts. The primary property loss policy of US$250 million has a deductible of US$10 million per incident and the primary business interruption policy of US$200 million has a deductible per incident of the greater of US$50 million gross earnings lost (as defined in the insurance policy) or 30 days from the incident. The excess coverage of US$700 million can be used for either property loss or business interruption coverage for its oil sands operations. For business interruption purposes, this excess coverage begins the later of full utilization of the primary business interruption coverage or 90 days from the date of the incident. Effective January 1, 2006, the excess coverage has a ceiling of US$40 WTI for the purposes of determining the loss for business interruption claims.

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, 2005, 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 $340 million of accounts receivable (2004 – $170 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, 2005, $340 million in outstanding accounts receivable had been sold under the program. Under the recourse provisions, the company will provide indemnification against credit losses for certain counterparties, which did not exceed $58 million in 2005. A liability has not 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, 2005, were $170 million and approximately $2,220 million, respectively. The company recorded an after-tax loss of approximately $4 million on the securitization program in 2005 (2004 – $2 million; 2003 – $3 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. As described in note 1, 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 has provided a residual value guarantee on the equipment of up to $7 million should it elect not to repurchase the equipment at the end of the lease term. Had the company elected to terminate the lease at December 31, 2005, the total cost would have been $21 million (2004 – $25 million). Annualized equipment lease payments in 2005 were $5 million (2004 – $6 million; 2003 – $4 million).

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.

(d) Subsequent Event

In January and February 2006, the company received an additional $175 million in proceeds related to its business interruption insurance coverage. The proceeds related to business activity during 2005 and have accordingly been recognized as revenue in the fourth quarter of 2005. This brings total proceeds from our business interruption claim to US$500 million out of the US$900 million available. The company is currently negotiating a final settlement with its business interruption insurers. Any subsequent proceeds will be recorded when unconditionally received or receivable.

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, 2002	448 972	578
Issued for cash under stock option plans	1 977	20
Issued under dividend reinvestment plan	235	6
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**

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 criteria. Once this right has been earned, these options are considered vested.

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

See next page for more technical details and amounts on the company's stock option plans.

(i) EXECUTIVE STOCK PLAN Under this plan, the company granted 518,000 common share options in 2005 (2004 – 1,346,000; 2003 – 1,902,000) 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 2005, the company granted 1,253,000 options (2004 – 1,742,000; 2003 – 1,305,000) 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. As the company had been accruing costs of these options, the impact on net earnings for 2005 was not significant. The remaining 50% of the outstanding, unvested SunShare options may vest on April 30, 2008 if the final predetermined performance criterion is met. If the performance criteria is not met, the unvested options that have not previously expired or been cancelled, will automatically vest on January 1, 2012.

(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 901,000 common share options in 2005 (2004 – nil, 2003 – 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 1,190,000 DSUs outstanding at December 31, 2005 (1,228,000 at December 31, 2004). DSUs were granted to certain executives under the company's former employee long-term incentive program. Certain members of the Board of Directors have also elected to receive DSUs in lieu of cash compensation. DSUs are only redeemable at the time a unitholder ceases employment or Board membership, as applicable.

In 2005, 81,000 DSUs were redeemed for cash consideration of $5 million (2004 – no redemption, 2003 – 185,000 redeemed for cash consideration of $5 million). Over time, DSU unitholders are entitled to receive additional DSUs equivalent in value to future notional dividend reinvestments. Final DSU redemption amounts are subject to change depending on the company's share price at the time of exercise. Accordingly, the company revalues the DSUs on each reporting date, with any changes in value recorded as an adjustment to compensation expense in the period. As at December 31, 2005, the total liability related to the DSUs was $87 million, of which $4 million was classified as current (see note 7).

During 2005, total pretax compensation expense related to deferred share units was $39 million (2004 – $12 million; 2003 – $8 million).

(v) PERFORMANCE SHARE UNITS (PSUs) During 2005, the company issued 453,000 PSUs (2004 – 354,000; 2003 – nil) under its new employee incentive 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 2005 was $21 million (2004 – $5 million; 2003 – $nil).

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, 2002	20 326	3.80 – 28.14	19.89
Granted	3 207	23.65 – 29.85	26.70
Exercised	(1 977)	3.80 – 23.93	10.35
Cancelled	(540)	10.13 – 27.93	20.94
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**
Exercisable, December 31, 2005	**9 361**	**5.28 – 42.65**	**21.77**

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)	**2005**	2004	2003
	10 724	4 342	6 893

The following table is an analysis of outstanding and exercisable common share options as at December 31, 2005:

	Outstanding			Exercisable	
Exercise Prices ($)	Number (thousands)	Weighted-average Remaining Contractual Life	Weighted-average Exercise Price Per Share ($)	Number (thousands)	Weighted-average Exercise Price Per Share ($)
5.28 – 10.13	912	3	9.51	912	9.51
12.28 – 21.35	3 074	4	15.38	3 074	15.38
23.65 – 31.45	10 586	6	27.12	4 753	26.51
32.22 – 43.45	3 505	8	37.79	622	35.20
45.51 – 71.13	1 126	7	57.26	—	—
Total	19 203	6	28.12	9 361	21.77

(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:

	2005	2004	2003
Annual dividend per share	**$0.24**	$0.23	$0.1925
Risk-free interest rate	**3.69%**	3.79%	4.39%
Expected life	**6 years**	6 years	7 years
Expected volatility	**28%**	29%	32%
Weighted-average fair value per option	**$15.42**	$12.02	$9.94

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)	**2005**	2004	2003
Net earnings attributable to common shareholders – as reported	**1 245**	1 088	1 087
Less: compensation cost under the fair value method for pre-2003 options	**13**	47	30
Pro forma net earnings attributable to common shareholders for pre-2003 options	**1 232**	1 041	1 057
Basic earnings per share			
As reported	**2.73**	2.40	2.42
Pro forma	**2.70**	2.30	2.35
Diluted earnings per share			
As reported	**2.67**	2.36	2.26
Pro forma	**2.64**	2.26	2.20

12. EARNINGS PER COMMON SHARE

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

($ millions)	**2005**	2004	2003
Net earnings attributable to common shareholders	**1 245**	1 088	1 087
(millions of common shares)			
Weighted-average number of common shares	**456**	453	450
Dilutive securities:			
Options issued under stock-based compensation plans	**10**	9	8
Redemption of preferred securities by the issuance of common shares	**—**	—	22
Weighted-average number of diluted common shares	**466**	462	480
(dollars per common share)			
Basic earnings per share [(a)]	**2.73**	2.40	2.42
Diluted earnings per share [(b)]	**2.67**	2.36	2.26

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)	**2005**	2004	2003
Interest on debt	**151**	157	185
Capitalized interest	**(119)**	(62)	(63)
Net interest expense	**32**	95	122
Foreign exchange (gain) on long-term debt	**(37)**	(82)	(213)
Other foreign exchange (gain) loss	**(10)**	11	17
Total financing expenses (income)	**(15)**	24	(74)

Cash interest payments in 2005 totalled $149 million (2004 – $152 million; 2003 – $184 million).

15. INVENTORIES

($ millions)	**2005**	2004
Crude oil	**279**	194
Refined products	**124**	120
Materials, supplies and merchandise	**120**	109
Total	**523**	423

The replacement cost of crude oil and refined product inventories exceeded their LIFO carrying value by $202 million (2004 – $65 million) as at December 31, 2005.

During 2005, the company recorded a pretax gain of $16 million related to a permanent reduction in LIFO inventory layers (2004 – $8 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)	**2005**	2004	2003
Operating revenues			
Sales to Energy Marketing and Refining – Canada segment joint ventures:			
Refined products	**327**	320	301
Petrochemicals	**279**	272	187

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, 2005, amounts due from Energy Marketing and Refining – Canada segment joint ventures were $22 million (2004 – $17 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)	**2005**	2004	2003
Export sales [(a)]	**648**	693	549
Exploration expenses			
Geological and geophysical	**22**	33	18
Other	**1**	1	1
Cash costs	**23**	34	19
Dry hole costs	**33**	21	32
Cash and dry hole costs [(b)]	**56**	55	51
Leasehold impairment [(c)]	**13**	8	16
	69	63	67
Taxes other than income taxes			
Excise taxes [(d)]	**482**	496	428
Production, property and other taxes	**47**	44	38
	529	540	466
Allowance for doubtful accounts	**4**	3	

(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	**2005**	2004	2003
Net earnings as reported, Canadian GAAP		**1 245**	1 088	1 087
Adjustments				
Derivatives and hedging activities	(a)	**83**	92	(176)
Stock-based compensation	(b)	**(26)**	(10)	(2)
Asset retirement obligations	(c)	**—**	—	7
Income tax expense		**(28)**	(27)	54
Net earnings from continuing operations, U.S. GAAP		**1 274**	1 143	970
Cumulative effect of change in accounting principles, net of income taxes of $nil (2004 – $nil; 2003 – $23)	(c)	**—**	—	(66)
Net earnings, U.S. GAAP		**1 274**	1 143	904
Derivatives and hedging activities, net of income taxes of $70 (2004 – $35; 2003 – $7)	(a)	**140**	(67)	18
Minimum pension liability, net of income taxes of $8 (2004 – $3; 2003 – $nil)	(d)	**(15)**	5	7
Foreign currency translation adjustment	(e)	**(26)**	(29)	(26)
Comprehensive income, U.S. GAAP		**1 373**	1 052	903

per common share (dollars)	**2005**	2004	2003
Net earnings per share from continuing operations, U.S. GAAP			
Basic	**2.79**	2.52	2.16
Diluted	**2.73**	2.47	2.02
Net earnings per share, U.S. GAAP			
Basic	**2.79**	2.52	2.01
Diluted	**2.73**	2.47	1.88

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

	Notes	**December 31, 2005** As Reported	**December 31, 2005** U.S. GAAP	December 31, 2004 As Reported	December 31, 2004 U.S. GAAP
Current assets	(a,f)	**1 916**	**1 916**	1 195	1 300
Property, plant and equipment, net	(f)	**12 966**	**12 966**	10 326	10 340
Deferred charges and other	(a,d)	**469**	**500**	320	367
Total assets		**15 351**	**15 382**	11 841	12 007
Current liabilities	(a)	**1 935**	**1 935**	1 409	1 701
Long-term borrowings	(a,f)	**3 007**	**3 029**	2 217	2 275
Accrued liabilities and other	(d)	**1 005**	**1 092**	749	815
Future income taxes	(a,d)	**3 274**	**3 247**	2 545	2 526
Share capital	(b)	**732**	**780**	651	699
Contributed surplus	(b)	**50**	**88**	32	44
Cumulative foreign currency translation	(e)	**(81)**	**—**	(55)	—
Retained earnings		**5 429**	**5 341**	4 293	4 176
Accumulated other comprehensive income	(a,d,e)	**—**	**(130)**	—	(229)
Total liabilities and shareholders' equity		**15 351**	**15 382**	11 841	12 007

(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 U.S. dollar 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, 2005 the company had hedged a portion of its forecasted Canadian dollar denominated cash flows subject to U.S. dollar WTI commodity price risk for 2006 and 2007. The company has not hedged any portion of the foreign exchange component of these forecasted cash flows.

While the company's current strategic intent is to only manage the exposure relating to changes in the U.S. dollar WTI component of its crude oil sales, 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.

During 2005, the company recognized $2 million of hedging losses that, under U.S. GAAP, would have been recognized as hedge ineffectiveness losses in prior periods. Under U.S. GAAP, for the year ended December 31, 2005, the company would have recognized $2 million of hedge ineffectiveness relating to forecasted cash flows in 2006 and 2007 primarily due to foreign exchange fluctuations during the period (2004 – $57 million ineffectiveness relating to 2005 forecasted cash flows). The net earnings impact of this ineffectiveness will not be recognized for Canadian GAAP purposes until the related forecasted crude oil 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, 2005, the company had interest rate derivatives classified as fair value hedges outstanding for up to six years relating to fixed rate debt.

De-designated Hedging Instruments

During 2003, the company de-designated and monetized purchased crude oil call option hedging instruments for net proceeds of $28 million. For Canadian GAAP purposes, as it was probable that the underlying forecasted crude oil sales would occur, the related $28 million pretax gain on monetization of the call options was deferred and recognized as additional crude oil revenues during 2004. For U.S. GAAP purposes, the company recognized the $28 million pretax gain as hedge ineffectiveness income during 2003.

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)	**2005**	2004
OCI attributable to derivatives and hedging activities, beginning of the period, net of income taxes of $69 (2004 – $34)	**(138)**	(71)
Current period net changes arising from cash flow hedges, net of income taxes of $2 (2004 – $61)	**(3)**	(122)
Net hedging losses at the beginning of the period reclassified to earnings during the period, net of income taxes of $72 (2004 – $26)	**143**	55
OCI attributable to derivatives and hedging activities, end of period, net of income taxes of $1 (2004 – $69)	**2**	(138)

For the year ended December 31, 2005, assets increased by $22 million and liabilities increased by $22 million as a result of recording all derivative instruments at fair value in accordance with U.S. GAAP.

The earnings loss associated with realized and unrealized hedge ineffectiveness on derivative contracts designated as cash flow hedges during the period was $3 million, net of income taxes of $2 million (2004 – loss of $130 million, net of income taxes of $66 million; 2003 – loss of $199 million, net of income taxes of $93 million). The company estimates that $4 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, 2005 U.S. GAAP net earnings increased by $55 million, net of income taxes of $28 million (2004 – increased net earnings of $65 million, net of income taxes of $27 million; 2003 – decreased net earnings of $120 million, net of income taxes of $56 million) to reflect the impact of the above items.

(b) Stock-based Compensation

Under Canadian GAAP, compensation expense has not been recognized for common share options granted prior to January 1, 2003, including options issued in connection with both the company's SunShare long-term incentive plan, as well as those common shares and common share options awarded to employees under the company's previous long-term incentive program that matured April 1, 2002. Under U.S. GAAP, certain of the SunShare options would have been accounted for using the variable method of accounting for employee stock compensation. Further, for U.S. GAAP purposes, compensation expense is recognized ratably over the life of the previous long-term incentive program for those options and common shares awarded under that plan. For the year ended December 31, 2005, U.S. GAAP net earnings would have been reduced by $26 million (2004 – $10 million; 2003 – $2 million) to reflect additional stock-based compensation expense.

Under Canadian GAAP, the company now expenses the compensation cost of all common share options issued after January 1, 2003 ratably over the estimated vesting period of the respective options. For U.S. GAAP purposes, the company would have adopted Statement 148 in 2003, permitting the company to expense common share options issued after January 1, 2003 in a manner consistent with Canadian GAAP.

Consistent with Canadian GAAP, for U.S. GAAP purposes the company would have continued to disclose pro forma stock-based compensation cost for common stock options awarded prior to January 1, 2003 ("pre-2003 options") as if the fair value method had been adopted. Under U.S. GAAP, had the company accounted for its pre-2003 options using the fair value method (excluding the earnings effect of the SunShare and long-term employee incentive options described above), pro forma net earnings and pro forma basic earnings per share for the year ended December 31, 2005 would have been reduced by $4 million (2004 – $37 million; 2003 – $27 million) and $0.01 per share (2004 – $0.08; 2003 – $0.06), respectively.

(c) Asset Retirement Obligations

Under Canadian GAAP, the company retroactively adopted Canadian accounting standards related to asset retirement obligations on January 1, 2004, with restatements of all prior period comparative amounts. Under U.S. GAAP the company would have adopted asset retirement obligations on January 1, 2003 and would have been required to record the cumulative effect of the change in accounting policy in 2003 earnings. This GAAP difference would have decreased U.S. GAAP net earnings by $61 million in 2003 (net of future income taxes of $21 million).

(d) Minimum Pension Liability

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.

Under U.S. GAAP, at December 31, 2005, the company would have recognized a minimum pension liability of $87 million (2004 – $66 million), an intangible asset of $9 million (2004 – $11 million) and an other comprehensive loss of $51 million, net of income taxes of $27 million (2004 – $36 million, net of income taxes of $19 million). Other comprehensive income for the year ended December 31, 2005 would have decreased by $15 million, net of income taxes of $8 million (2004 – an increase in other comprehensive income of $5 million, net of income taxes of $3 million; 2003 – an increase in other comprehensive income of $7 million, net of income taxes of $nil).

(e) Cumulative Foreign Currency Translation

Under Canadian GAAP, foreign currency losses of $26 million (2004 – $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.

(f) Variable Interest Entities

For U.S. GAAP purposes, the company consolidated the VIE related to the sale of equipment as described in note 10c as of January 1, 2004. The impact on the December 31, 2004 balance sheet would be an increase to property, plant and equipment of $14 million, an increase to materials and supplies inventory of $8 million and an increase to long-term debt of $22 million. The VIE was consolidated for Canadian GAAP purposes effective January 1, 2005 without restatement of prior periods (see note 1).

The accounts receivable securitization program, as currently structured, does not meet the FIN 46 (R) criteria for consolidation by Suncor (see note 10c).

(g) 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)	**2005**	2004	2003
Balance, beginning of year	**5**	1	—
Additions pending determination of proved reserves	**14**	5	1
Charged to dry hole expense	**(2)**	—	—
Reclassifications to proved properties	**(2)**	(1)	—
Balance, end of year	**15**	5	1
Capitalized for a period greater than one year ($ millions)	**1**	—	—
Number of projects that have exploratory well costs capitalized for a period greater than 12 months	**2**	—	—

(h) 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 (net versus gross reported). The EITF is effective for transactions entered into subsequent to April 1, 2006.

As required by EITF 04-13, we record certain crude oil, natural gas, petroleum product and chemical purchases and sales entered into contemporaneously with the same counterparty on a net basis within the "purchases of crude oil and products" line in the Consolidated Statements of Earnings. 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 2005, 2004 and 2003 are shown below.

($ millions)	**2005**	2004	2003
Consolidated revenues	**11 086**	8 665	6 611
Amounts included in revenues for purchase/sale contracts with the same counterparty [1]	**16**	7	—

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

Recently Issued Accounting Standards

In December 2004, the U.S. Financial Accounting Standards Board issued SFAS 123(R), "Share-Based Payment". The standard, effective January 1, 2006, 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, SFAS 123(R) requires recognition of compensation expense for the portion of outstanding unvested awards granted prior to the effective date. The company currently records an expense under Canadian GAAP for all common share options issued on or after January 1, 2003, with a corresponding increase recorded as contributed surplus in the Consolidated Statements of Changes in Shareholders' Equity. The company expects the adoption of SFAS 123R on January 1, 2006, for U.S. GAAP reporting purposes will not have a significant impact on net earnings.

In 2005, the FASB issued SFAS 153, "Exchange of Non-monetary Assets". Effective January 1, 2006, all non-monetary transactions must be measured at fair value (if determinable) unless the transaction lacks commercial substance, or is an exchange of a product held for sale in the ordinary course of business, or is a product to be sold in the same line of business. Commercial substance exists when the company's future cash flows are expected to change significantly as a result of a transaction. The company will be 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 will be recorded. The amount of the gross up of revenues and purchases of crude oil products will be dependent on the prevailing prices for natural gas. Currently the transaction is recorded net in purchases of crude oil and products. Retroactive adjustment is prohibited by the standard.

In May 2005, the FASB issued SFAS No. 154, "Accounting Changes and Error Corrections". Among other changes, this Statement requires retrospective application for voluntary changes in accounting principle, unless it is impractical to do so. This Statement is effective on a prospective basis beginning January 1, 2006.

In November 2004, the FASB issued SFAS No. 151, "Inventory Costs, an amendment of ARB No. 43, Chapter 4." This Statement clarifies that items, such as abnormal idle facility expense, excessive spoilage, double freight, and handling costs, be recognized as current-period charges. In addition, the Statement requires that allocation of fixed production overheads to the costs of conversion be based on the normal capacity of the production facilities. Suncor is required to implement this Statement in 2006. The company does not expect the standard to have a significant impact on earnings or financial position.

The U.S. Emerging Issues Task Force (EITF) has issued EITF Abstract 04-6 "Accounting for Stripping Costs Incurred during Production in the Mining Industry". The abstract is effective January 1, 2006. The EITF consensus is that stripping (overburden removal) costs incurred during the production phase of a mine are variable production costs that should be included in the costs of inventory produced during the period. Up until December 31, 2005, the company has deferred and amortized stripping costs for Canadian GAAP purposes. The company is currently assessing whether to expense overburden stripping costs as incurred (see Summary of Significant Accounting Policies page 65).

QUARTERLY SUMMARY (unaudited)

FINANCIAL DATA

($ millions except per share amounts)	For the Quarter Ended Mar 31 2005	June 30 2005	Sept 30 2005	Dec 31 2005	Total Year 2005	For the Quarter Ended Mar 31 2004	June 30 2004	Sept 30 2004	Dec 31 2004	Total Year 2004
Revenues	**2 061**	**2 380**	**3 142**	**3 503**	**11 086**	1 806	2 212	2 326	2 321	8 665
Net earnings (loss)										
Oil Sands	**117**	**117**	**253**	**586**	**1 073**	239	231	263	261	994
Natural Gas	**26**	**27**	**24**	**78**	**155**	22	35	23	35	115
Energy Marketing and Refining – Canada	**(3)**	**5**	**17**	**22**	**41**	30	(3)	29	24	80
Refining and Marketing – U.S.A. [c]	**6**	**31**	**50**	**55**	**142**	(3)	12	15	10	34
Corporate and eliminations	**(48)**	**(68)**	**(3)**	**(47)**	**(166)**	(72)	(73)	7	3	(135)
	98	**112**	**341**	**694**	**1 245**	216	202	337	333	1 088
Per common share										
Net earnings attributable to common shareholders										
Basic	**0.22**	**0.24**	**0.75**	**1.52**	**2.73**	0.48	0.45	0.74	0.73	2.40
Diluted	**0.21**	**0.24**	**0.73**	**1.48**	**2.67**	0.46	0.43	0.73	0.72	2.36
Cash dividends	**0.06**	**0.06**	**0.06**	**0.06**	**0.24**	0.05	0.06	0.06	0.06	0.23
Cash flow from (used in) operations										
Oil Sands	**252**	**215**	**445**	**983**	**1 895**	365	421	509	457	1 752
Natural Gas	**83**	**81**	**104**	**144**	**412**	83	90	80	66	319
Energy Marketing and Refining – Canada	**22**	**26**	**44**	**60**	**152**	56	23	52	57	188
Refining and Marketing – U.S.A. [c]	**18**	**52**	**82**	**95**	**247**	(6)	21	21	23	59
Corporate and eliminations	**(81)**	**(69)**	**(24)**	**(56)**	**(230)**	(84)	(65)	(77)	(79)	(305)
	294	**305**	**651**	**1 226**	**2 476**	414	490	585	524	2 013

OPERATING DATA

OIL SANDS

(thousands of barrels per day)

Production [1]										
Base operations	**121.2**	**119.5**	**125.2**	**263.3**	**157.6**	213.9	210.8	230.2	206.9	215.6
Firebag	**18.7**	**8.7**	**23.0**	**26.0**	**19.1**	5.9	15.1	7.3	15.6	10.9
	139.9	**128.2**	**148.2**	**267.7**	**171.3**	219.8	225.9	237.5	222.5	226.5
Sales										
Light sweet crude oil	**75.3**	**48.3**	**69.9**	**108.6**	**73.3**	112.2	118.7	113.5	115.3	114.9
Diesel	**11.8**	**9.0**	**10.6**	**30.7**	**15.6**	27.5	29.7	28.7	25.5	27.9
Light sour crude oil	**38.5**	**54.2**	**41.7**	**104.2**	**59.8**	74.3	68.9	76.3	80.9	75.1
Bitumen	**18.4**	**9.6**	**22.3**	**7.2**	**16.6**	—	14.5	7.9	11.0	8.4
	144.0	**121.1**	**144.5**	**250.7**	**165.3**	214.0	231.8	226.4	232.7	226.3

OPERATING DATA (continued)

	For the Quarter Ended				Total Year	For the Quarter Ended				Total Year
	Mar 31 2005	**June 30 2005**	**Sept 30 2005**	**Dec 31 2005**	**2005**	Mar 31 2004	June 30 2004	Sept 30 2004	Dec 31 2004	2004
OIL SANDS (continued)										
Average sales price [2]										
(dollars per barrel)										
Light sweet crude oil	**45.41**	**39.20**	**52.08**	**55.96**	**49.93**	40.26	45.70	46.03	50.55	45.60
Other (diesel, light sour crude oil and bitumen)	**47.31**	**50.47**	**59.70**	**63.84**	**56.90**	35.85	38.28	42.29	39.62	39.13
Total	**46.44**	**45.98**	**56.01**	**60.42**	**53.81**	38.16	41.88	44.08	44.68	42.28
Total [a]	**54.80**	**57.24**	**67.95**	**66.68**	**62.68**	43.28	48.18	52.72	54.40	49.78
Cash operating costs and total operating costs – Base Operations										
(dollars per barrel sold rounded to the nearest $0.05)										
Cash costs	**15.10**	**16.30**	**18.00**	**12.90**	**14.95**	9.65	9.75	9.00	10.90	9.80
Natural gas	**4.70**	**2.65**	**4.60**	**3.40**	**3.75**	2.10	2.30	1.40	2.20	2.00
Firebag bitumen	**—**	**—**	**—**	**1.60**	**0.75**	—	—	—	—	—
Imported bitumen	**0.10**	**—**	**—**	**0.10**	**0.05**	0.40	0.05	0.10	0.10	0.15
Cash operating costs [3]	**19.90**	**18.95**	**22.60**	**18.00**	**19.50**	12.15	12.10	10.50	13.20	11.95
Firebag start-up costs	**—**	**—**	**—**	**0.30**	**0.10**	1.20	—	—	—	0.30
Total cash operating costs [4]	**19.90**	**18.95**	**22.60**	**18.30**	**19.60**	13.35	12.10	10.50	13.20	12.25
Depreciation, depletion and amortization	**9.05**	**9.45**	**9.00**	**6.20**	**8.00**	6.20	6.20	5.70	6.25	6.10
Total operating costs [5]	**28.95**	**28.40**	**31.60**	**24.50**	**27.60**	19.55	18.30	16.20	19.45	18.35
Cash operating costs and total operating costs – Firebag										
Cash costs	**8.90**	**18.95**	**6.85**	**6.25**	**8.45**	—	6.55	14.90	7.00	8.30
Natural gas	**10.10**	**16.40**	**13.70**	**13.40**	**13.05**	—	11.65	11.90	10.45	11.20
Cash operating costs [6]	**19.00**	**35.35**	**20.55**	**19.65**	**21.50**	—	18.20	26.80	17.45	19.50
Depreciation, depletion and amortization	**4.75**	**7.60**	**4.10**	**4.60**	**4.90**	—	5.80	7.45	5.55	6.00
Total operating costs [7]	**23.75**	**42.95**	**24.65**	**24.25**	**26.40**	—	24.00	34.25	23.00	25.50
NATURAL GAS										
Gross production [b]										
Natural gas (millions of cubic feet per day)	**191**	**175**	**200**	**193**	**190**	197	209	201	193	200
Natural gas liquids (thousands of barrels per day)	**3.0**	**2.2**	**2.2**	**2.3**	**2.4**	2.2	2.2	2.6	2.9	2.5
Crude oil (thousands of barrels per day)	**0.9**	**1.0**	**0.7**	**0.6**	**0.8**	0.9	1.1	1.0	1.0	1.0
Total (barrels of oil equivalent per day at 6:1 for natural gas)	**35.7**	**32.4**	**36.3**	**35.0**	**34.8**	35.9	38.1	37.1	36.1	36.8
Average sales price [2]										
Natural gas (dollars per thousand cubic feet)	**6.81**	**7.29**	**8.32**	**11.66**	**8.57**	6.54	6.77	6.49	7.02	6.70
Natural gas [a] (dollars per thousand cubic feet)	**6.74**	**7.26**	**8.34**	**11.83**	**8.59**	6.59	6.84	6.53	6.98	6.73
Natural gas liquids (dollars per barrel)	**38.32**	**52.52**	**58.00**	**57.85**	**50.70**	38.13	43.53	42.06	46.46	42.82
Crude oil – conventional (dollars per barrel)	**61.40**	**63.86**	**63.77**	**72.60**	**64.85**	44.14	47.08	55.43	55.26	50.41

OPERATING DATA (continued)

	For the Quarter Ended				Total Year	For the Quarter Ended				Total Year
	Mar 31 2005	**June 30 2005**	**Sept 30 2005**	**Dec 31 2005**	**2005**	Mar 31 2004	June 30 2004	Sept 30 2004	Dec 31 2004	2004
ENERGY MARKETING AND REFINING – CANADA										
Refined product sales (thousands of cubic metres per day)	**15.1**	**16.1**	**15.6**	**14.3**	**15.2**	15.2	15.5	15.3	15.6	15.4
Margins										
Refining [8] (cents per litre)	**4.8**	**7.3**	**9.2**	**9.0**	**7.6**	7.8	7.4	8.8	7.9	8.0
Refining [8], [a] (cents per litre)	**4.8**	**7.6**	**10.1**	**9.3**	**8.0**	7.8	8.0	8.8	7.8	8.1
Retail [9] (cents per litre)	**4.7**	**3.8**	**5.4**	**6.4**	**5.1**	5.0	4.3	3.7	4.5	4.4
Utilization of refining capacity (%)	**91**	**100**	**96**	**95**	**95**	108	85	104	101	100
REFINING AND MARKETING – U.S.A. [c]										
Refined product sales (thousands of cubic metres per day)	**10.1**	**12.6**	**17.3**	**14.5**	**13.7**	8.1	8.9	10.9	9.5	9.3
Margins										
Refining [8] (cents per litre)	**6.3**	**9.5**	**8.9**	**10.4**	**9.0**	5.0	9.0	5.1	7.7	6.7
Refining [8], [a] (cents per litre)	**6.3**	**9.5**	**8.9**	**10.4**	**9.0**	5.0	9.3	5.3	7.7	6.8
Retail [9] (cents per litre)	**3.3**	**4.3**	**7.5**	**5.4**	**5.1**	5.0	6.2	4.2	6.0	5.4
Utilization of refining capacity (%)	**96**	**102**	**104**	**91**	**98**	85	86	99	100	92

(a) Excludes the impact of hedging activities.

(b) Currently all 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 production – In the fourth quarter of 2005, base operations production included barrels from both mining and in-situ operations that were upgraded. Firebag production reported in the operating summary includes all in-situ production irrespective of whether it was upgraded or sold to third parties. As such these production figures as reported in the operating summary are not additive in the fourth quarter of 2005 and the year ended December 31, 2005.

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

(3) Cash operating costs – base operations – Include cash costs that are defined as operating, selling and general expenses (excluding inventory changes), accretion expense, taxes other than income taxes and the cost of bitumen imported from third parties. Per barrel amounts are based on production volumes that are processed through the upgrader facilities. For a reconciliation of this non GAAP financial measure see page 57 of MD&A.

(4) Total cash operating costs – base operations – Include cash operating costs – Base operations as defined above and cash start-up costs for in-situ operations. Per barrel amounts are based on all production volumes that are processed through the upgrader facilities.

(5) Total operating costs – base operations – Include total cash operating costs – Base operations as defined above and non-cash operating costs. Per barrel amounts are based on all production volumes that are processed through the upgrader facilities.

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

(7) Total operating costs – Firebag – Include cash operating costs – Firebag as defined above and non-cash operating costs. Per barrel amounts are based on in-situ production volumes.

(8) Refining margin – Calculated as the average wholesale unit price from all products less average unit cost of crude oil.

(9) Retail margin – Calculated as the average street price of Sunoco (Energy, Marketing and Refining – Canada) and Phillips 66-branded (Refining and Marketing – U.S.A.) retail gasoline net of federal excise tax, as applicable, and other adjustments, less refining gasoline transfer price.

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)	**2005**[a]	2004	2003[a]	2002	2001
Revenues					
Oil Sands	**3 965**	3 640	3 101	2 655	1 404
Natural Gas	**679**	567	512	339	481
Energy Marketing and Refining – Canada	**4 299**	3 460	2 936	2 508	2 673
Refining and Marketing – U.S.A.	**2 621**	1 495	515	—	—
Corporate and eliminations	**(478)**	(497)	(453)	(431)	(232)
	11 086	8 665	6 611	5 071	4 326
Net earnings (loss)					
Oil Sands	**1 073**	994	887	781	271
Natural Gas	**155**	115	120	34	116
Energy Marketing and Refining – Canada	**41**	80	53	61	79
Refining and Marketing – U.S.A.	**142**	34	18	—	—
Corporate and eliminations	**(166)**	(135)	9	(156)	(117)
	1 245	1 088	1 087	720	349
Cash flow from (used in) operations					
Oil Sands	**1 895**	1 752	1 803	1 475	486
Natural Gas	**412**	319	298	164	280
Energy Marketing and Refining – Canada	**152**	188	164	112	165
Refining and Marketing – U.S.A.	**247**	59	34	—	—
Corporate and eliminations	**(230)**	(305)	(259)	(358)	(132)
	2 476	2 013	2 040	1 393	799
Capital and exploration expenditures					
Oil Sands	**1 948**	1 119	953	618	1 495
Natural Gas	**363**	279	184	163	132
Energy Marketing and Refining – Canada	**442**	228	122	60	54
Refining and Marketing – U.S.A.	**337**	190	31	—	—
Corporate	**63**	31	32	37	13
	3 153	1 847	1 322	878	1 694
Total assets	**15 351**	11 841	10 540	9 046	8 467
Capital employed [b]					
Short-term and long-term debt, less cash and cash equivalents	**2 891**	2 159	2 577	3 204	3 678
Shareholders' equity	**6 130**	4 921	3 893	2 886	2 220
	9 021	7 080	6 470	6 090	5 898
Less capitalized costs related to major projects in progress	**(2 175)**	(1 467)	(1 122)	(511)	(3 691)
	6 846	5 613	5 348	5 579	2 207
Total Suncor employees (number at year-end)	**5 152**	4 605	4 231	3 422	3 307

FIVE-YEAR FINANCIAL SUMMARY (unaudited) (continued)

	2005 [a]	2004	2003 [a]	2002	2001
Dollars per common share					
Net earnings attributable to common shareholders	**2.73**	2.40	2.42	1.61	0.78
Cash dividends	**0.24**	0.23	0.1925	0.17	0.17
Cash flow from operations	**5.43**	4.44	4.53	3.11	1.79
Ratios					
Return on capital employed (%) [b], [c]	**20.9**	19.0	18.3	14.5	17.8
Return on capital employed (%) [d]	**15.3**	16.1	16.0	13.7	7.3
Return on shareholders' equity (%) [e]	**22.5**	24.7	32.1	28.2	16.8
Debt to debt plus shareholders' equity (%) [f]	**33.3**	31.4	43.2	52.7	62.4
Net debt to cash flow from operations (times) [g]	**1.2**	1.1	1.3	2.3	4.6
Interest coverage – cash flow basis (times) [h]	**16.9**	13.8	11.5	8.1	4.2
Interest coverage – net earnings basis (times) [i]	**13.4**	10.9	10.1	6.2	2.5

(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 and short-term debt plus 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 twelve month period ended; divided by average capital employed. Average capital employed is the sum of shareholders' equity and short-term debt plus long-term debt less cash and cash equivalents, at the beginning and end of the year, divided by two, less average capitalized costs related to major projects in progress (as applicable). Return on capital employed (ROCE) for Suncor operating segments presented in the Quarterly Operating Summary is calculated in a manner consistent with consolidated ROCE. For a detailed annual reconciliation of this non GAAP financial measure see page 56 of MD&A.

(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 2005	**June 30 2005**	**Sept 30 2005**	**Dec 31 2005**	Mar 31 2004	June 30 2004	Sept 30 2004	Dec 31 2004
Share ownership								
Average number outstanding, weighted monthly (thousands) [(a)]	**454 911**	**456 141**	**456 996**	**457 429**	452 123	452 283	452 565	453 900
Share price (dollars)								
Toronto Stock Exchange								
High	**50.07**	**60.24**	**73.25**	**76.05**	38.02	36.80	41.49	44.49
Low	**38.76**	**44.00**	**57.75**	**57.00**	31.62	30.95	32.80	38.20
Close	**48.73**	**57.92**	**70.42**	**73.32**	35.97	34.01	40.40	42.40
New York Stock Exchange – US$								
High	**41.70**	**48.95**	**62.50**	**66.00**	28.75	28.09	32.63	36.15
Low	**31.33**	**35.38**	**47.40**	**48.09**	24.68	22.55	24.90	31.16
Close	**40.21**	**47.32**	**60.53**	**63.13**	27.35	25.61	32.01	35.40
Shares traded (thousands)								
Toronto Stock Exchange	**107 080**	**102 317**	**108 384**	**107 502**	100 401	109 073	102 460	86 424
New York Stock Exchange	**84 285**	**89 244**	**139 214**	**175 618**	45 120	59 254	64 519	66 536
Per common share information (dollars)								
Net earnings attributable to common shareholders	**0.22**	**0.24**	**0.75**	**1.52**	0.48	0.45	0.74	0.73
Cash dividends	**0.06**	**0.06**	**0.06**	**0.06**	0.05	0.06	0.06	0.06

(a) The company had approximately 2,420 holders of record of common shares as at January 31, 2006.

Information for Security Holders Outside Canada

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

SUPPLEMENTAL FINANCIAL AND OPERATING INFORMATION (unaudited)

	2005	2004	2003	2002	2001
OIL SANDS					
Production (thousands of barrels per day)	**171.3**	226.5	216.6	205.8	123.2
Sales (thousands of barrels per day)					
Light sweet crude oil	**73.3**	114.9	112.3	104.7	56.2
Diesel	**15.6**	27.9	26.3	23.0	14.8
Light sour crude oil	**59.8**	75.1	73.3	68.3	42.0
Bitumen	**16.6**	8.4	6.4	9.3	8.5
	165.3	226.3	218.3	205.3	121.5
Average sales price (dollars per barrel)					
Light sweet crude oil	**49.93**	45.60	40.26	37.56	34.17
Other (diesel, light sour crude oil and bitumen)	**56.90**	39.13	33.93	29.58	24.86
Total	**53.81**	42.28	37.19	33.65	29.17
Total [(a)]	**62.68**	49.78	40.22	36.94	34.21
Cash operating costs – base operations [(b)]	**19.50**	11.95	11.45	11.15	11.35
Total cash operating costs – base operations [(b)]	**19.60**	12.25	11.45	11.15	11.35
Total operating costs – base operations [(b)]	**27.60**	18.35	17.25	17.25	16.70
Cash operating costs – Firebag [(b), (e)]	**21.50**	19.50	—	—	—
Total operating costs – Firebag [(b), (e)]	**26.40**	25.50	—	—	—
Capital employed excluding major projects in progress	**4 633**	4 169	4 050	4 512	1 378
Return on capital employed (%) [(c)]	**24.3**	22.9	20.8	16.7	19.6
Return on capital employed (%) [(d)]	**17.6**	18.8	17.4	15.6	6.2

(a) Excludes the impact of hedging activities.

(b) Dollars per barrel rounded to the nearest $0.05. See definitions on page 100.

(c) See definitions on page 102.

(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) Firebag stage 1 commenced commercial operations on April 1, 2004.

	2005	2004	2003	2002	2001
NATURAL GAS					
Production					
Natural gas (millions of cubic feet per day)					
Gross	**190**	200	187	179	177
Net	**137**	147	142	124	124
Natural gas liquids (thousands of barrels per day)					
Gross	**2.4**	2.5	2.3	2.4	2.4
Net	**1.9**	1.8	1.7	1.7	1.7
Crude oil (thousands of barrels per day)					
Gross	**0.8**	1.0	1.4	1.5	1.5
Net	**0.7**	0.8	1.1	1.2	1.1
Total (thousands of boe [a] per day)					
Gross	**34.8**	36.8	34.9	33.7	33.4
Net	**25.3**	27.1	26.4	23.6	23.5
Average sales price					
Natural gas (dollars per thousand cubic feet)	**8.57**	6.70	6.42	3.91	6.09
Natural gas (dollars per thousand cubic feet) [b]	**8.59**	6.73	6.42	3.91	6.12
Natural gas liquids (dollars per barrel)	**50.70**	42.82	36.08	29.35	34.38
Crude oil – conventional (dollars per barrel)	**64.85**	50.41	40.29	31.72	33.92
Capital employed	**563**	448	400	422	291
Return on capital employed (%) [e]	**30.7**	27.1	29.2	9.5	34.2
Undeveloped landholdings [c]					
Oil and gas (millions of acres)					
Western Canada					
Gross	**0.6**	0.7	0.5	0.5	0.6
Net	**0.4**	0.5	0.4	0.4	0.5
International					
Gross	**0.4**	0.7	0.9	1.2	1.7
Net	**0.2**	0.4	0.2	0.7	1.3
Net wells drilled [d]					
Exploratory					
Oil	**—**	—	—	—	—
Gas	**8**	5	2	2	4
Dry	**4**	5	31	19	16
Development					
Oil	**1**	—	1	—	—
Gas	**18**	16	16	18	16
Dry	**3**	—	4	4	2
	34	26	54	43	38

(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 22 net exploratory wells and 10 net development wells in progress at the end of 2005.
(e) See definitions on page 102.

	2005	2004	2003	2002	2001
ENERGY MARKETING AND REFINING – CANADA					
Refined product sales (thousands of cubic metres per day)					
Transportation fuels					
Gasoline					
Retail [b]	**4.5**	4.6	4.4	4.5	4.3
Other	**3.9**	4.1	4.2	4.4	4.4
Jet fuel	**0.9**	0.9	0.7	0.4	0.7
Diesel	**3.3**	3.1	3.0	2.9	3.1
	12.6	12.7	12.3	12.2	12.5
Petrochemicals	**0.7**	0.8	0.8	0.6	0.5
Heating oils	**0.4**	0.4	0.5	0.4	0.4
Heavy fuel oils	**1.0**	0.7	0.8	0.6	0.8
Other	**0.5**	0.8	0.6	0.7	0.6
	15.2	15.4	15.0	14.5	14.8
Margins (cents per litre)					
Refining	**7.6**	8.0	6.5	4.8	5.7
Refining [c]	**8.0**	8.1	6.4	4.8	5.7
Retail	**5.1**	4.4	6.6	6.6	6.6
Crude oil supply and refining					
Processed at Sarnia refinery (thousands of cubic metres per day)	**10.6**	11.1	10.5	10.6	10.2
Utilization of refining capacity (%)	**95**	100	95	95	92
Capital employed excluding major projects in progress	**486**	512	551	485	480
Return on capital employed (%) [d]	**8.1**	14.6	10.3	12.0	18.3
Return on capital employed (%) [d], [e]	**5.2**	13.6	10.3	12.0	18.3
Retail outlets [f] (number at year-end)	**374**	378	379	384	400

	2005	2004	2003	2002	2001
REFINING AND MARKETING – U.S.A. [a]					
Refined product sales (thousands of cubic metres per day)					
Transportation fuels					
Gasoline					
Retail	**0.7**	0.7	0.7	—	—
Other	**6.2**	3.8	3.5	—	—
Jet fuel	**0.8**	0.5	0.5	—	—
Diesel	**3.3**	2.2	2.3	—	—
	11.0	7.2	7.0	—	—
Asphalt	**1.6**	1.5	1.7	—	—
Other	**1.1**	0.6	0.4	—	—
	13.7	9.3	9.1	—	—
Margins (cents per litre)					
Refining	**9.0**	6.7	5.9	—	—
Refining [c]	**9.0**	6.8	5.9	—	—
Retail	**5.1**	5.4	5.6	—	—
Crude oil supply and refining					
Processed at Denver refinery (thousands of cubic metres per day)	**12.1**	8.8	9.4	—	—
Utilization of refining capacity (%)	**98**	92	98	—	—
Capital employed excluding major projects in progress	**327**	232	270	—	—
Return on capital employed (%) [d], [h]	**49.4**	12.2	—	—	—
Return on capital employed (%) [d], [e], [h]	**28.9**	11.0	—	—	—
Retail outlets [g] (number at year-end)	**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 102.
(e) If capital employed were to include capitalized costs related to major projects in progress, the return on capital employed (ROCE) 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 and New York Stock Exchange under the symbol SU.

Dividends
Suncor's Board of Directors reviews its dividend policy quarterly. In 2005, Suncor paid an aggregate dividend of $0.24 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 optional 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 or visit www.computershare.com. Information regarding the purchase plan is also available in the stock information section of www.suncor.com.

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

Independent Auditors
PricewaterhouseCoopers LLP

Independent Reserve Evaluators
GLJ Petroleum Consultants Ltd.

Annual Meeting
Suncor's annual general meeting of shareholders will be held at 10:30 a.m. MT on April 26, 2006, 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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For further information, to subscribe or cancel duplicate mailings
In addition to annual and quarterly reports, Suncor publishes a biennial Report on Sustainability. All Suncor publications, as well as updates on company news as it happens, are available on our website at www.suncor.com. To subscribe to Suncor e-news, go to the newsroom section of our website. To order copies of Suncor's print materials call 1-800-558-9071.

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

Shareholders may elect to receive Suncor's Annual Report and other documents electronically. To register for electronic delivery, registered shareholders should visit www.computershare.com.

CORPORATE DIRECTORS AND OFFICERS

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, 2005, 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.

Committee	Key Responsibilities
Board Policy, Strategy Review and Governance Committee	Oversees key matters pertaining to 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 and 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.

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
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 PanGlobal Energy Ltd., Kanetax Energy Inc. and Tenax Inc. He is active with several charitable organizations including Shock Trauma Air Rescue Services (STARS), 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.

Brian A. Canfield (2,3)

Point Roberts, Washington
Chair, Human Resources and Compensation Committee
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.

Bryan P. Davies (1,4)

Toronto, Ontario
Director 1991 to 1996 and since 2000

Bryan Davies is president of Davtak (Canada) Inc., a policy consulting firm based in Toronto. He is also a director of the General Insurance Statistical Agency. He 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 is also active with numerous not-for-profit and charitable organizations, including serving 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 a partner in the law firm of Felesky Flynn LLP in Calgary, Alberta. Mr. Felesky also serves as a director on the board and chair of the audit committee of Epcor Power LP. He is also a member of the board of Precision Drilling Corporation and Fairquest Energy Ltd. Mr. Felesky is actively involved in not-for-profit and charitable organizations. 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 Canadian Unity Council and 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., a real estate company in Edmonton, Alberta. 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.

W. Douglas (Doug) Ford (1,4)

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 serves as chairman of the Canadian Council of Chief Executives.

John R. Huff (2,3)

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

John Huff is chairman and chief executive officer of Oceaneering International Inc., an oil field services company. Mr. Huff is also a director of BJ Services Company. He is active in a variety of non-profit organizations, including the American Bureau of Shipping, the Marine Resources Foundation, and St. Luke's Episcopal Hospital in Houston.

Robert W. Korthals (1)

Toronto, Ontario
Director since 1996

Robert Korthals is the former president of the Toronto-Dominion Bank. Mr. Korthals is currently chairman of the Ontario Teachers' Pension Plan Board. He is a director of Bucyrus International, Inc., Great Lakes Carbon Income Trust, Jannock Properties Limited, Rogers Communications Inc., easyHome Inc., Cognos Inc. and four structured split share funds traded on the TSX sponsored by Mulvihill Investments. In addition, Mr. Korthals serves as a director of the Canadian Parks and Wilderness Foundation.

M. Ann McCaig (3,4)

Calgary, Alberta
Chair, Environment,
Health and Safety Committee
Director since 1995

Ann McCaig is the president of VPI Investments Ltd., a private investment holding company. Mrs. McCaig is actively involved with charitable and community activities. She is currently chair of the Alberta Adolescent Recovery Centre, co-chair of the Alberta Children's Hospital Foundation $50 million All for One – All for Kids campaign, 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.

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. From 1992 to 2000, Mr. O'Brien was executive vice president of Suncor's wholly-owned subsidiary, Suncor Energy Products Inc. (formerly Sunoco Inc.). Mr. O'Brien also serves on the boards of PrimeWest Energy Inc. and Shaw Communications Inc. As well, he is past chair of the board of trustees for Nature Conservancy of Canada, past-chair of Canadian Petroleum Products Institute and past-chair of Canada's Voluntary Challenge for Global Climate Change.

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

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 the company's management proxy circular.

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.

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.

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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