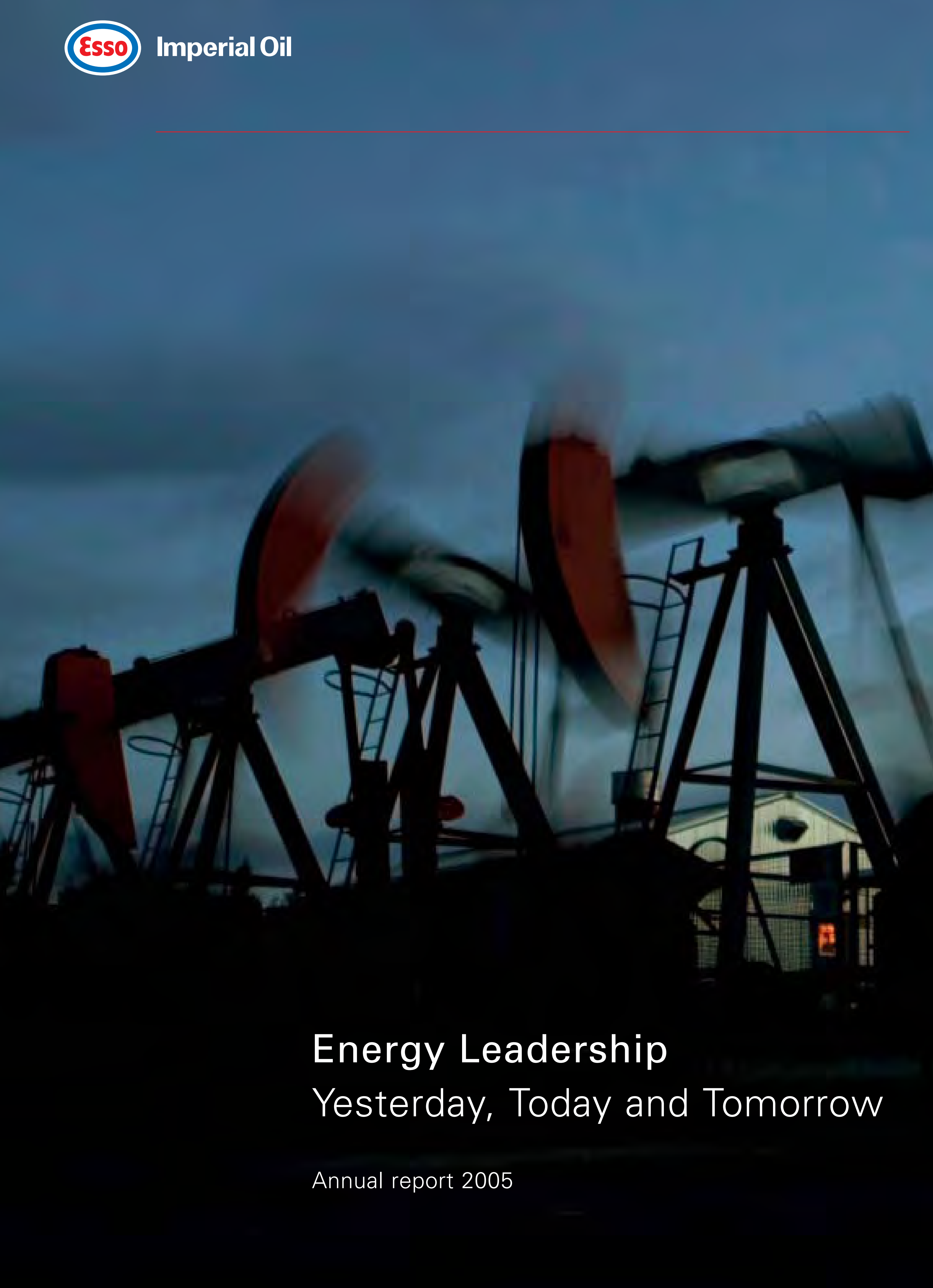
Imperial Oil



Energy Leadership
Yesterday, Today and Tomorrow

Annual report 2005

Contents

Corporate Profile

Imperial Oil is one of Canada's largest corporations and a leading member of the country's petroleum industry. It is one of Canada's largest producers of crude oil and natural gas and is also the country's largest refiner and marketer of petroleum products, sold primarily under the Esso and Mobil brand names through a coast-to-coast supply network that includes close to 2,000 retail outlets.

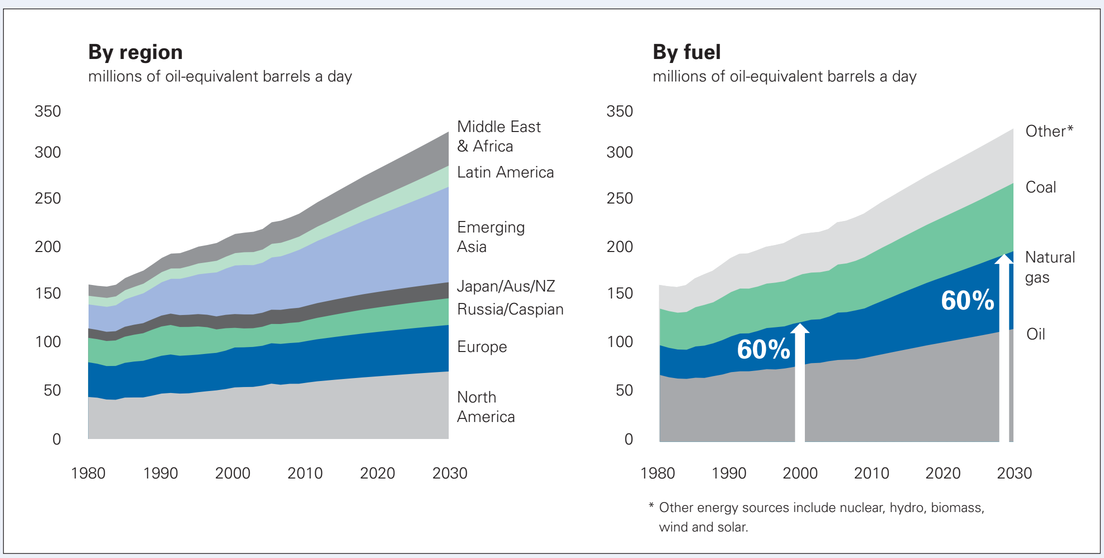
On site at Cold Lake, Imperial's wholly owned and operated in-situ oil sands operation. In addition to achieving record production levels in 2005, Cold Lake operations were recently named an EnviroVista Leader by the Alberta government, in recognition of environmental leadership and stewardship.

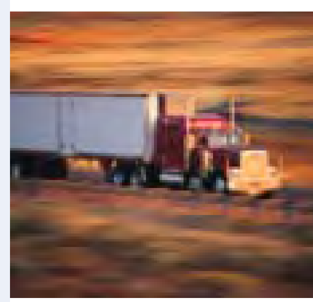
This report contains forward-looking information on future production, project start-ups and future capital spending. Actual results could differ materially as a result of market conditions or changes in law, government policy, operating conditions, costs, project schedules, operating performance, demand for oil and natural gas, commercial negotiations or other technical and economic factors.

The importance of energy

- Energy is essential to economic growth and social development, and the demand for energy is rising as populations and industries grow.
- The world continues to become more energy efficient, improving at an average rate of more than one percent a year.
- Even so, demand is projected to grow at an average rate of about 1.7 percent a year — from about 200 million oil-equivalent barrels a day in 2000 to more than 330 million oil-equivalent barrels by 2030.
- Growth in energy use will be strongest in developing countries, but North American demand for energy will also increase as economies expand.
- Hydrocarbons — oil, natural gas and coal — will continue to provide the dominant share of world energy supply. Oil and natural gas alone are expected to account for about 60 percent of the world's energy needs well into the foreseeable future.

World energy demand grows 1.7 percent a year



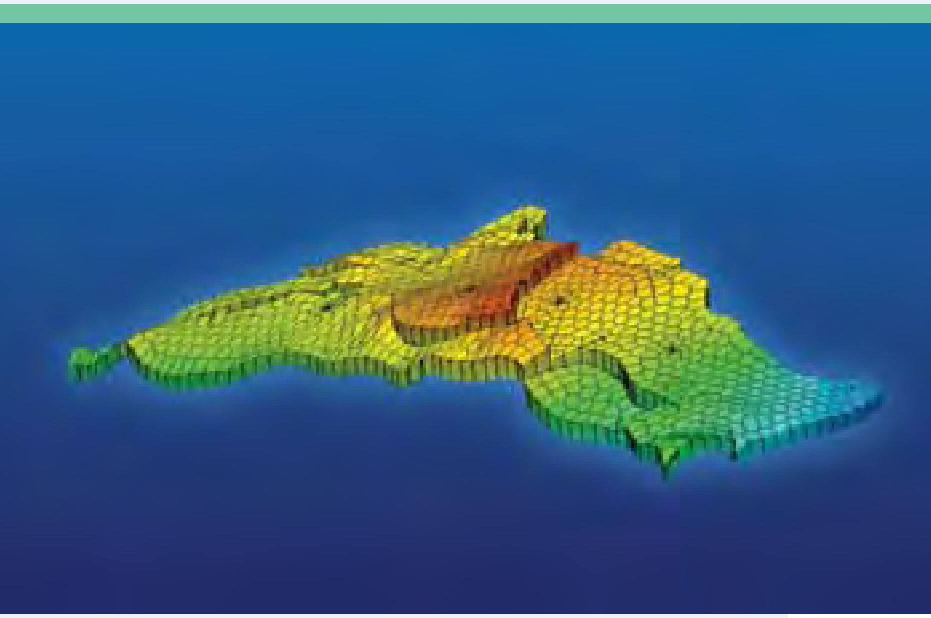


The world continues to improve in energy conservation and efficiency. Traditional fossil fuels are expected to supply the vast majority of energy needs in the foreseeable future.

Fossil fuels are vital to mobility and economic growth around the world — fuelling industry and providing myriad products that improve lives.

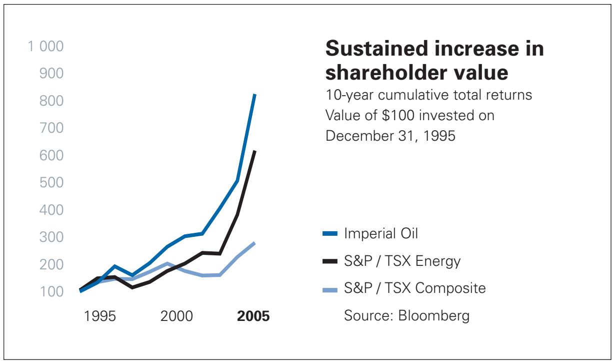
Resources are available to meet demand

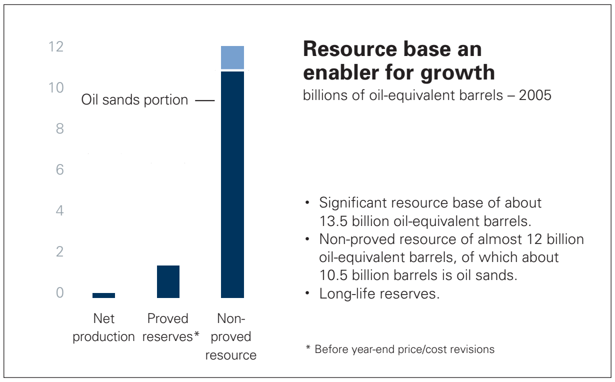
- Hydrocarbons are expected to remain the dominant source of the world's energy supply.
- Globally, total recoverable resources of hydrocarbons are estimated to be the equivalent of about 12 trillion barrels of oil, of which only about three trillion barrels, or about one quarter, have been consumed to date.
- The oil sands, with about 800 billion barrels of recoverable resource, will become an increasingly important contributor to world supply.
- The largest deposits of oil sands are located here in Canada. The nation is also rich in natural gas, with about 500 trillion cubic feet of recoverable resource potential estimated in basins across the country.
- Canada is uniquely positioned to participate in the growing global energy market and is one of the few industrialized countries with the resource potential to become an even larger producer and exporter of crude oil and natural gas.
- Technology has been, and will remain, essential to meeting growing energy demands. Technological advances such as extended-reach drilling, in-situ steam stimulation, advanced reservoir imaging and enhanced recovery techniques enable resources to be found, accessed and produced in ways not possible just a few years ago — bringing to market resources that would otherwise be uneconomic.



Technology will be essential to the development of Canada's resource base. Imperial's commitment to research has been unwavering, resulting in proprietary technologies and competitive advantages — particularly in the oil sands.

The Imperial Oil advantage





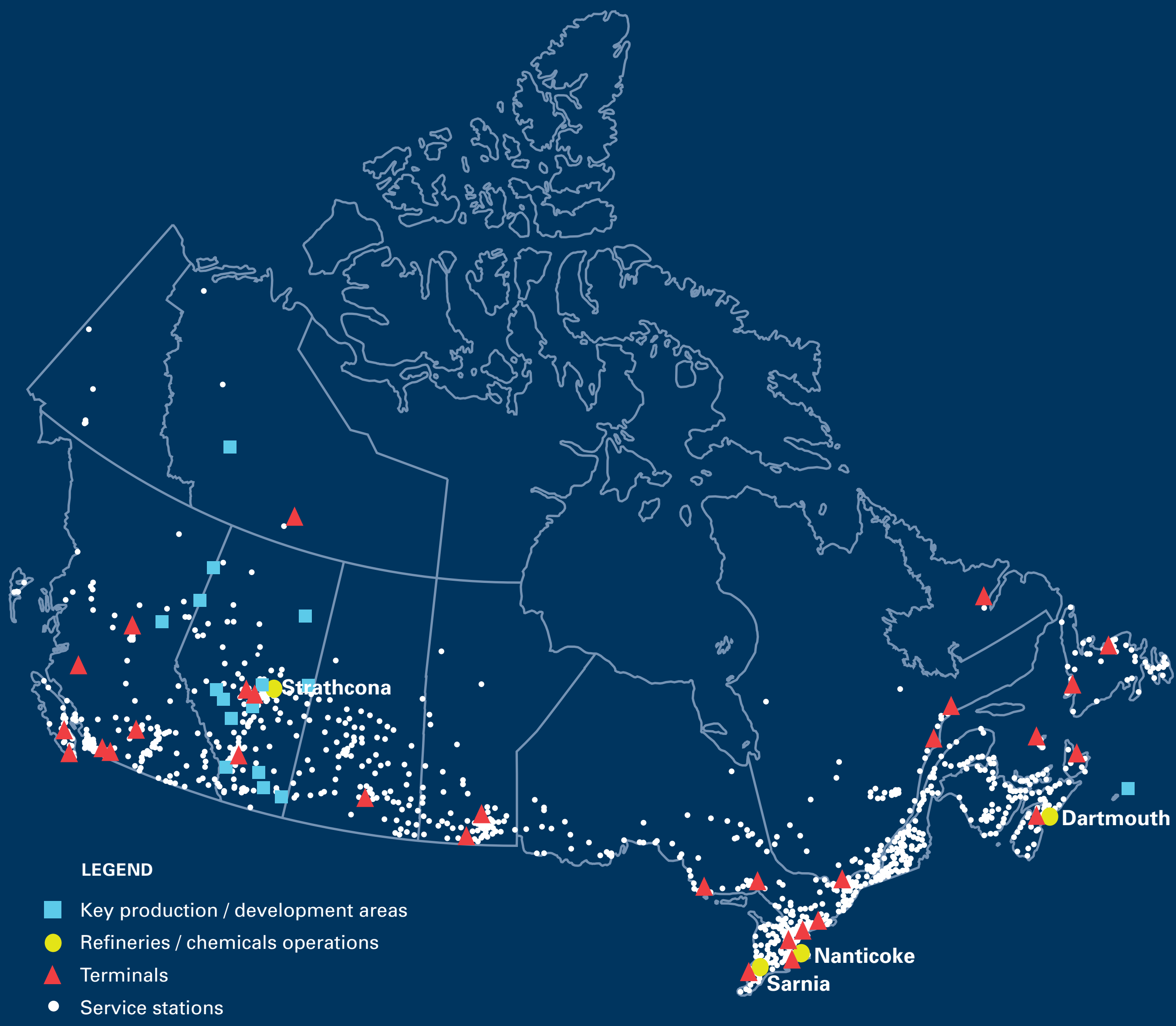
- A proven business model — based on investment discipline, prudent financial management and operational excellence.
- A record of delivering superior shareholder value by:
  - Developing Canada's leading resource base — *in a disciplined and environmentally responsible manner;*
  - Accessing and applying worldwide leading-edge technology — *to improve existing operations and unlock new opportunities;*
  - Continually improving base operations — *using worldwide best practices to improve efficiency and attain best-in-class costs;*
  - Leveraging financial strength that is unparalleled in the industry — *to pursue all opportunities that generate attractive returns;*
  - Following the highest ethical standards — *with high-performing employees running the business.*
- Imperial has provided superior returns to shareholders — in 2005, the total return was 64 percent and has averaged over 24 percent a year for the past 10 years. The company's return on capital employed is the highest of the Canadian integrated oil companies.

Financial highlights

	2005	2004	2003	2002	2001
Net income (millions of dollars)	**2 600**	2 052	1 705	1 214	1 223
Net income per share – diluted (dollars) (a)	**7.59**	5.74	4.58	3.20	3.11
Return on average shareholders' equity (percent) (b)	**40.2**	34.6	32.6	26.5	28.8
Return on average capital employed (percent) (c)	**32.6**	27.7	25.3	20.0	22.3
Annual shareholders' return (percent) (d)	**64.0**	25.3	30.5	3.2	14.5

(a) Calculated by reference to the average number of shares outstanding, weighted monthly (page 66).
(b) Net income divided by average shareholders' equity (page 40).
(c) A definition of return on average capital employed can be found on page 33.
(d) Includes share appreciation and dividends.

Imperial's coast-to-coast operations . . .



. . . are diverse

>80	13	4	30	2,000
Active production and development properties	Company-owned pipelines	Refinery sites	Terminal locations	Service stations

Letter to shareholders

Our company takes pride in meeting the energy needs of Canadians in safe, reliable and environmentally responsible ways. We provide a product that is in strong demand and improves the quality of life. We operate in one of Canada's most dynamic industry sectors. And within this sector, we are an industry leader dedicated to increasing shareholder value.

In 2005, record earnings of $2.6 billion ($7.59 per share) were generated, along with industry-leading return on capital employed of 33 percent and cash flow from operating activities of $3.5 billion. Regular per-share annual dividend payments increased for the 11th year in a row. And the combination of dividend payments and share price appreciation provided shareholders with a total return of 64 percent.

Higher oil and natural gas prices and refining margins were strong contributors to improved financial performance. The business environment was not the only factor contributing to the improvement, however. By continuing to follow our proven business model — investment discipline, prudent financial management and operational excellence — we took steps to improve base operations and pursue new opportunities, laying the groundwork for future performance.

In 2005, for example, we continued to be an industry leader in safety, achieving best-ever safety performance for both employees and contractors.

In the downstream business, refining profitability was enhanced through sound operational management, with a disciplined focus on controlling costs and maximizing reliability. We also made substantial environmental investments, such as improvements to produce ultra-low sulphur diesel, a fuel that will reduce vehicle emissions. And our Esso-branded retail network was upgraded in major urban markets, focusing on opportunities to increase productivity.

In upstream operations, several major resource opportunities were advanced. Syncrude's multi-year project to expand bitumen-upgrading capacity neared completion. A regulatory application was filed for Kearl, a proposed oil sands mining project near Fort McMurray that could ultimately produce up to 300,000 barrels a day over its life span. And together with our Mackenzie gas project co-venturers, sufficient progress was made on land access, revenue-sharing agreements and regulatory process certainty to be able to proceed to public hearings into the proposed pipeline project. This is a landmark energy project that offers significant benefits to the country, the people of the North, natural gas consumers and producers.

To advance these and other projects, the company invested about $1.5 billion in capital and exploration expenditures in 2005 — about the same level as in the last three years.

The year also brought a significant change for our organization with the relocation of the head office from Toronto to Calgary. By bringing the company together geographically, the move will assist with overall organizational effectiveness and improve the focus on business opportunities in Western and Northern Canada.

In 2005, one of the major factors underlying high oil and natural gas prices was robust world demand for energy. Long-term forecasts suggest that as economies develop and populations increase, global energy demand will continue to grow — by as much as 50 percent by 2030 from current levels — and that oil and natural gas will remain dominant sources of energy well into the foreseeable future. This outlook is quite promising for Imperial, which possesses the country's leading resource base — about 13.5 billion oil-equivalent barrels.

Energy prices will likely continue to be volatile, driven by the changing fundamentals of supply and demand and geopolitical events. Regardless, our company will remain focused on being the lowest-cost producer. This approach, together with access to worldwide industry-leading technology and an attractive resource base, will enable us to maintain financial strength, despite evolving market conditions.

The company's ongoing success is directly attributable to the talent, ingenuity and commitment of its employees. Thanks to their efforts, the company delivered another successful year.

Looking ahead, I believe that the company's prospects are strong. Today we are well positioned to extend our leadership in the energy industry, with a healthy balance sheet, access to abundant resource opportunities across Canada and a talented and dedicated workforce. We have delivered superior long-term results, and we will continue to do so, while maintaining a focus on sound governance, ethics, integrity, safety and environmental excellence. Building on and continually strengthening this tradition of energy leadership is a cornerstone of our business — yesterday, today and tomorrow.

T.J. (Tim) Hearn
Chairman, president and
chief executive officer

February 15, 2006

Year in review

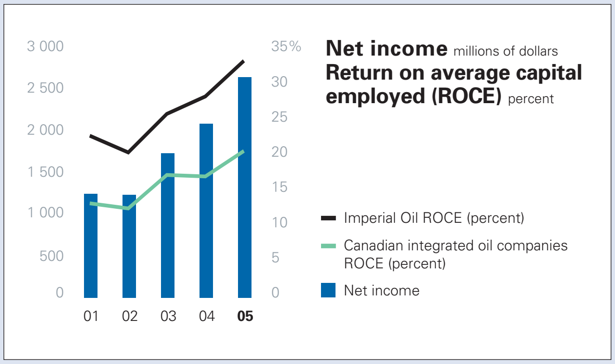
Top – State-of-the-art water treatment facilities at the Cold Lake, Alberta oil sands operation.

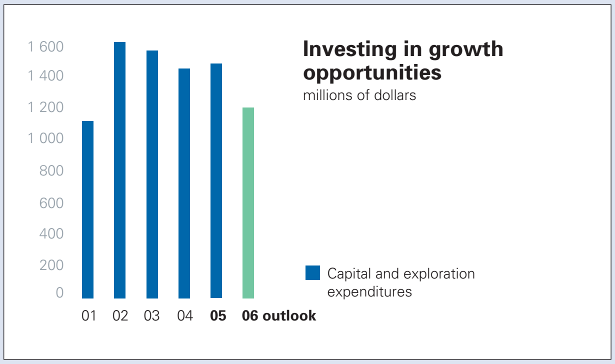
Middle – An Esso service station in Oakville, Ontario. One of about 2,000 service stations across Canada.

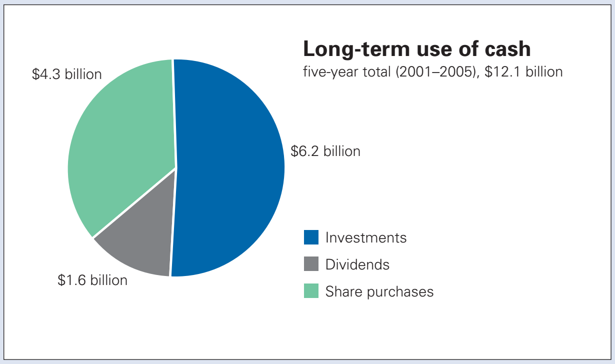
Bottom – The lubricants packaging plant at the Strathcona, Alberta refinery.

Operating highlights

- Average daily production before royalties totalled 358,000 oil-equivalent barrels of crude oil, natural gas liquids and natural gas. Average daily sales of petroleum products averaged 89 million litres.
- Company operations were strong and refinery utilization remained at record levels despite a significant amount of planned maintenance.
- Average production at the Cold Lake heavy oil operation was a record 139,000 barrels a day before royalties.
- Best-ever safety performance was achieved for both employees and contractors.
- Several environmental performance measures showed improvement through the year.
- Substantial progress was made on the Stage 3 expansion at Syncrude, with start-up anticipated by mid-2006.
- Regulatory applications were filed with the Alberta Energy and Utilities Board to develop Imperial's proposed bitumen-mining project at Kearl, located northeast of Fort McMurray.
- Imperial and its co-venturers on the Mackenzie gas project made sufficient progress on land access, revenue-sharing agreements, and regulatory process certainty to proceed to public hearings.
- A second 3-D seismic program was completed in the Orphan Basin leases off the East Coast of Newfoundland and an exploration well will be drilled in 2006.
- Total research expenditures in Canada at the company's two research facilities were $50 million, and a total of eight patents were awarded. Through its relationship with Exxon Mobil Corporation, the company had access to more than $700 million of industry-leading research conducted during the year.







Financial highlights

- The company achieved record earnings of $2,600 million in 2005, $7.59 per share, up from the previous record of $2,052 million, $5.74 per share, in 2004.
- Imperial maintains the leading return on capital employed in the industry — 33 percent.
- In 2005, the total annual return on shares, including share price appreciation and dividends, was 64 percent.
- Regular per-share annual dividend payments increased for the 11th year in a row.
- Total distributions to shareholders, through dividend payments and share repurchases, were $2,112 million.
- A strong balance sheet was maintained in 2005. Debt as a percentage of total capital was below 18 percent; interest coverage was more than 88 times on an earnings basis and 101 times on a cash flow basis. Imperial maintained its "AAA" rating on Canadian debt from Standard & Poor's — the only Canadian industrial company with this rating.
- Capital and exploration expenditures totalled about $1.5 billion in 2005. These investments included advancing major upstream projects and funding significant refinery upgrades to produce ultra-low sulphur diesel. In 2006, capital and exploration expenditures are expected to total $1.2 billion, slightly lower than in 2005, as several major projects near completion. These investments will focus on growth and productivity improvements, and will be financed through internally generated funds.

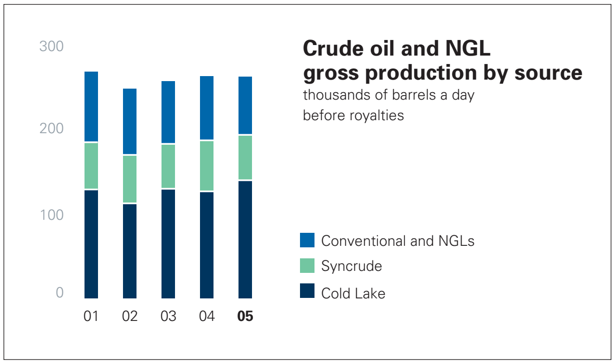
Natural resources

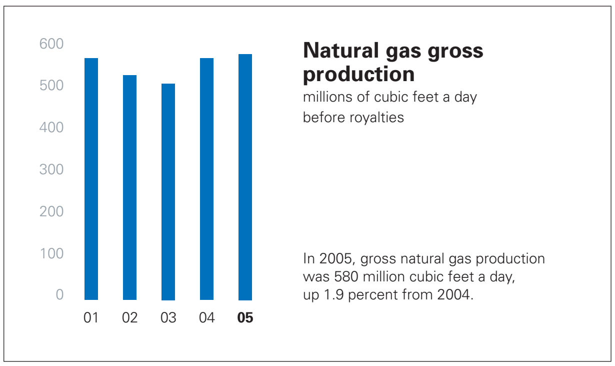
Imperial is developing Canada's leading resource base. Proved reserves are 1.6 billion oil-equivalent barrels, representing future production in bitumen, synthetic crude oil, conventional crude oil, natural gas and natural gas liquids. This represents only a fraction of the ultimate potential, as the company's non-proved resource base is about 12 billion oil-equivalent barrels.

The expansion project at Syncrude, located near Fort McMurray, is nearing completion. Imperial holds a 25-percent interest in Syncrude — the world's largest producer of crude oil from the oil sands.

Natural resources at a glance

	2005	2004	2003	2002	2001
Net income (millions of dollars)	**2 008**	1 517	1 174	1 052	953
Cash flow from operating activities and asset sales (millions of dollars)	**2 805**	2 395	1 729	1 276	1 248
Gross crude oil and NGL production (thousands of barrels a day)	**261**	262	256	247	267
Gross natural gas production (millions of cubic feet a day)	**580**	569	513	530	572
Capital employed at December 31 (millions of dollars)	**3 778**	3 870	3 744	3 265	2 586
Return on average capital employed (percent)	**52.5**	39.8	33.5	36.0	40.0





Imperial is a major producer of natural gas in Canada. In 2005, the company participated in a shallow gas development program that saw 239 wells drilled in southeastern Alberta.

The upstream business continued its record of superior operating performance in 2005. Solid operations and strong reliability saw volumes of 358,000 oil-equivalent barrels a day before royalties in 2005, essentially unchanged from 2004. The business generated record earnings of $2,008 million, cash flow from operating activities and asset sales of $2,805 million and a return on capital employed of 53 percent.

Upstream investment totalled over $900 million in 2005 and planned expenditures for 2006 will be about $800 million.

Oil sands

Imperial recognized the strategic importance of the oil sands more than 40 years ago. Today, 460,000 acres of leases are held, with non-proved oil sands resources of more than 10 billion barrels. Proven expertise in oil sands research and operations will enable development of these assets in an efficient and environmentally responsible manner, using technology to unlock previously unrecoverable deposits.

Combined production from the company's interests in both in-situ and mineable oil sands averaged 192,000 barrels of oil a day before royalties in 2005.

Production from Cold Lake averaged 139,000 barrels a day before royalties in 2005 — a new record for the site. Cold Lake has been developed using a phased approach, which enables emerging technologies to be applied as they become available. Because the bitumen is too viscous to be pumped in its natural state, it is heated in situ (in place) with high-pressure steam. The production process for this thermal operation is cyclic in nature, with alternating periods of steaming, soaking and production. Cycle times range from six months for new wells to 36 months for mature wells. In 2005, the 4,000 operating wells at Cold Lake produced as much as all other Canadian in-situ operations combined.

Regulatory approval was received in early 2004 to further expand Cold Lake operations within the current lease area. The operation is now producing from an area of about 70 square miles (about 180 km^2) but has an approved development area of almost twice that size. Development drilling in 2005 focused in the new expansion area, located north of the current operating area, and construction began on two new production "megapads."

All profitable near-term enhancement opportunities are being pursued to maximize the value generated from prior investments and minimize operating costs. For example, use of existing infrastructure to produce resources from new development areas ensures productive use of existing capital.

Production from Imperial's 25-percent interest in Syncrude, where bitumen is mined and upgraded into synthetic crude oil, was 53,000 barrels of synthetic crude oil a day before royalties. Production was down from 60,000 barrels a day in 2004 — a result of increased maintenance activities.

Construction on the Stage 3 expansion at Syncrude continued in 2005 and by year-end was 98 percent complete. The new 100,000-barrel-a-day coker — the third one — is expected to start up in the first half of 2006. Production of higher-quality synthetic crude oil from the new hydrotreating facilities is expected to commence by mid-2006. As a result of higher construction and labour costs in the region, the cost for the entire project is now estimated to be $8.4 billion (with Imperial's share estimated to be $2.1 billion), which is higher than the revised estimate provided in March 2004. The upgrader expansion will add an additional 25,000 barrels a day to Imperial's share of Syncrude volumes.

Extensive oil sands interests outside of Cold Lake and Syncrude are also held. The company is currently advancing pre-development work at Kearl, a proposed bitumen-mining project about 70 km northeast of Fort McMurray. Kearl is the best new mining development opportunity in Alberta's Athabasca region. Large by any standard, Kearl is estimated to contain about 4.4 billion barrels of recoverable resource, and it has the largest recoverable bitumen content as a share of total mined volume of all the proposed oil sands projects. Imperial holds a 70-percent interest in the project and would act as operator in a joint venture with ExxonMobil Canada. In 2005, initial engineering work continued, while process selection and mine plan development was completed. The current design basis involves a phased development approach, which enables better management of capital construction costs. The initial phase calls for a 100,000-barrel-a-day mine train and two subsequent expansions could increase production to approximately 300,000 barrels a day. A regulatory application was filed for the project in July, and hearings are scheduled to begin in mid-2006. Community consultations continue.

Conventional Western Canada

Imperial is among Canada's largest producers of conventional crude oil and natural gas. In 2005, production averaged 69,000 barrels a day of conventional crude oil and natural gas liquids and 580 million cubic feet of natural gas a day before royalties.

Conventional assets in Western Canada are mature but highly profitable and are being produced in a measured manner, with an emphasis on controlling costs, regardless of the pricing environment. In 2005, the majority of the company's conventional crude oil production came from its Norman Wells operation, where a major discovery made over 80 years ago established what is still the most northerly producing oil field in Canada.

While much of the conventional resource in Western Canada has been produced, economic development opportunities still exist — particularly in natural gas fields. In 2005, Imperial participated in a shallow gas development program that saw 239 wells drilled in southeastern Alberta. In northeast British Columbia, the development of natural gas assets at the Gwillim property continued, with additional drilling planned in 2006.

In certain properties where oil recovery is complete, the remaining gas caps — the natural gas that lies above the economically depleted reservoir — are being selectively produced. In 2005, production from gas caps at Wizard Lake and Nisku in west-central Alberta averaged about 240 million cubic feet of natural gas a day before royalties. Production rates at Wizard Lake are expected to decline in 2007 as the gas cap is depleted.

In 2005, as part of the company's ongoing practice to divest non-core assets, the wholly owned and operated Redwater field was sold, in addition to interests in the North Pembina field, with a gain on sale of the assets of $163 million after tax. The share of oil and natural gas production from these two properties averaged about 4,000 oil-equivalent barrels a day before royalties, which represents about one percent of the company's total production on an oil-equivalent basis.

Proved reserves of crude oil and natural gas (a)

	Crude oil and NGLs millions of barrels						Natural gas billions of cubic feet		Synthetic crude oil millions of barrels	
	Conventional		Cold Lake		Total				Syncrude	
year ended	gross	net	gross	net	gross	net	gross	net	gross	net
2001	197	165	926	807	1 123	972	1 670	1 414	914	821
2002	175	146	895	801	1 070	947	1 445	1 224	893	800
2003	151	126	853	763	1 004	889	1 204	1 023	874	781
2004 (b)	134	110	783	702	917	812	1 034	880	835	757
2005 (b)	**95**	**77**	**753**	**683**	**848**	**760**	**927**	**765**	**816**	**738**

(a) Gross reserves are the company's share of reserves before deducting the shares of mineral owners or governments or both. Net reserves exclude these shares.

(b) Before year-end price/cost revisions.

Cold Lake — four decades of technology in action

Research and technology is a cornerstone of our operations and is a tangible sign of a commitment to continuous improvement. Technology improves profitability in existing operations — and can turn uneconomic ideas into profitable opportunities.

Research efforts have been particularly important in the development of Canada's oil sands. There is virtually no exploration risk here — the bitumen deposits are known to exist and are well-delineated on oil sands leases. The key to developing the oil sands is in the technology that will improve recovery and reduce costs while minimizing environmental impacts.

Imperial pioneered the commercial development of Canada's oil sands through company-patented technologies. Notable examples for in-situ production include cyclic steam stimulation (1966) and steam-assisted gravity drainage (SAGD — 1982). The company was also instrumental in developing the means to recycle produced water (1978) and the use of other non-potable water sources (1993), which reduce the reliance on fresh water.

Research and technology investments totalling $250 million were made prior to the start-up of commercial development at Cold Lake in 1985. Since then, research expenditures related to this operation have averaged more than $25 million a year at the company's research centre in Calgary and in field pilots at Cold Lake.

The commitment to technology is ongoing. A pilot project to enhance recovery of bitumen using a solvent injected with the steam has been in operation at Cold Lake since 2002. Results are encouraging, and plans for larger-scale implementation are being developed. This technology has the potential to increase recovery in areas already in production as well as making lower-quality deposits economic. The addition of solvent is also being tested with SAGD technology at Imperial's oil sands research centre and will be piloted on company leases in the near future.

Over the next five years, development will continue in the northern extension area of Cold Lake. Current plans call for the use of "megapad" technology, which uses both horizontal and vertical wells constructed with a patented wellbore completion technique. This design enables greater reservoir access from a single-surface location, which reduces development costs and improves economics — another example of technology in action at Cold Lake.

On site at Cold Lake, a field production operator begins his day.

East Coast

On Canada's East Coast, the company holds a nine-percent interest in the Sable offshore energy project. The project currently produces natural gas from five fields located 250 km southeast of Halifax. Additional compression facilities designed to maintain current production levels are scheduled for start-up in late 2006. During the year, three additional wells were drilled at the newest field of this development, South Venture, in addition to a seventh well at the Venture location.

The Orphan Basin, a large unexplored region located in the deep waters off the East Coast of Newfoundland, is another area of interest. The company holds a 15 percent stake in eight deepwater exploration licences. A second 3-D seismic program was conducted on the leases in 2005, and an exploration well will commence drilling in 2006, with possible follow-up activity in 2007.

Mackenzie gas project

The Mackenzie gas project is a proposed multi-year, multi-billion-dollar project. It includes a 1,400-km natural gas pipeline system along the Mackenzie Valley in Canada's Northwest Territories that would connect northern onshore natural gas fields with North American markets. The project, including construction of gathering pipelines and associated facilities, would enable natural gas resources in three onshore anchor fields in the Mackenzie Delta to be developed.

Imperial's wholly owned Taglu field is estimated to have recoverable resources of about three trillion cubic feet, with a projected initial production rate of 400 million cubic feet a day before royalties. This field represents about one-half of the discovered onshore gas that the Mackenzie gas project would develop.

The initial cost for the project is estimated to be about $7 billion, which includes the development of three anchor fields, the gas-gathering system, a gas-processing plant at Inuvik and the Mackenzie Valley pipeline itself. Imperial's share of the project cost, including development of the Taglu anchor field and the company's share of the gas-gathering, processing and transmission system, is estimated to be about $3 billion.

In late April 2005, Imperial Oil, on behalf of the Mackenzie gas project co-venturers, halted project execution activities due to insufficient progress on key areas critical to the project — the finalization of benefits and access agreements, the establishment of a clear regulatory process including timelines and appropriate fiscal terms. Sufficient advances were subsequently made in these areas, and, in November, the co-venturers notified the National Energy Board of the project proponents' readiness to proceed to public hearings on the project, marking another milestone in the regulatory process. Hearings began in January 2006, and a decision from regulatory bodies is expected in 2007.

During 2005, initial applications for fieldwork approvals, including land-use permits and water licences, were filed with regulatory agencies and boards. Additional permit applications will be filed in 2006.

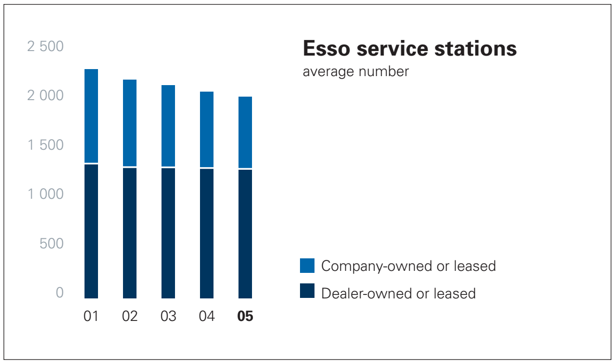
Petroleum products

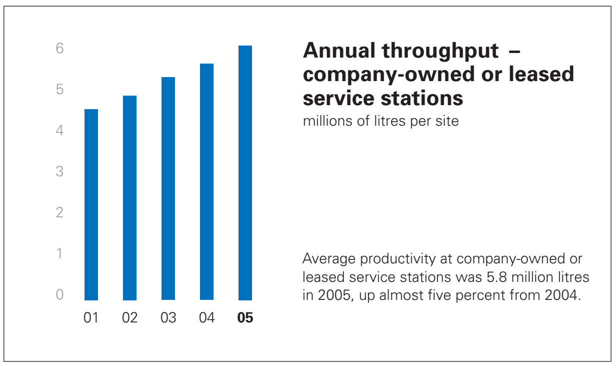
Imperial is a market leader in Canada, with the leading market share in petroleum products, including retail sales and finished lubricants. The company is also the nation's largest refiner, with almost double the capacity of its closest competitor.

Imperial operates manufacturing, blending and packaging facilities for lubricants in both the east and west — the only Canadian company to do so.

Petroleum products at a glance

	2005	2004	2003	2002	2001
Net income (millions of dollars)	**694**	556	462	147	376
Cash flow from operating activities and asset sales (millions of dollars)	**874**	946	706	448	882
Refinery throughput (millions of litres a day)	**74.1**	74.3	71.6	71.2	71.4
Petroleum product sales (millions of litres a day)	**89.1**	87.6	85.0	83.1	81.2
Capital employed at December 31 (millions of dollars)	**2 642**	2 524	2 707	2 334	2 164
Return on average capital employed (percent)	**26.9**	21.3	18.3	6.5	16.7





Over the past decade, the petroleum products segment has undergone a focused reshaping to hone a quality asset base. Unwavering attention to reliability, efficiency and best-in-class costs in all operations has been essential to the strong results now being achieved in increasingly competitive markets.

The petroleum products business achieved record earnings of $694 million in 2005, up 25 percent from record results of $556 million in 2004. On a cent-per-litre basis, earnings after tax for petroleum products was 2.1 cents per litre, versus 1.7 cents per litre in 2004. Return on average capital employed was 27 percent and cash flow from operating activities and asset sales was $874 million, of which $478 million was reinvested in the business.

Overall, operations performed well in 2005. Refinery utilization remained at record levels despite a significant amount of planned maintenance at the company's four refineries. Total refinery utilization for the year was 93 percent and record production rates were set at several refining units. Total petroleum product sales were 89.1 million litres a day — up almost two percent from 2004.

Industry refining margins were higher in 2005, driven by increased demand for refined petroleum products that stemmed from generally stronger global economic conditions and the short-term production disruptions along the U.S. Gulf Coast.

The company's ongoing focus on improving those aspects of margins within its control also increased refining margins that were realized in the year. For example, work in recent years has concentrated on refinery capability to process a broader range of economically available crude oil. The mix of refined products produced has also been optimized to increase the yield of higher-value products.

Improving air quality through low-sulphur fuels — reducing smog-forming emissions

By the end of 2006, the company will have spent more than $1.2 billion to reduce the sulphur content of gasoline and diesel. These initiatives will reduce smog-causing nitrogen oxides and particulate-matter emissions from new vehicles by almost 90 percent.

Approximately $600 million is being spent on providing ultra-low sulphur diesel, primarily at the company's four refineries. Government regulations call for sulphur levels in on-road diesel to be reduced to 15 parts per million by June 1, 2006 (at point of production), a reduction of about 97 percent. The investment program is on track to meet this deadline, which will ensure this fuel is available for 2007 model vehicles whose engine designs will require this fuel quality.

This investment follows a $650-million project, completed in 2003, that reduced sulphur levels in gasoline by more than 90 percent.

Imperial has long pursued a strategy to ensure that capital is productively used, that facilities operate reliably and that each business is performing at best-in-class cost levels. A key tactic in minimizing operating costs has been to focus on refinery energy efficiency, which has been improved by 16 percent overall since 1994.

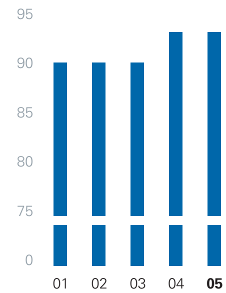
In 2005, upgrading of the retail network in major urban markets continued, which contributed to increased site productivity. There are 690 company-owned or leased sites with average productivity of 5.8 million litres a year, up five percent from 2004. Convenience store and car-wash sales also increased, by six percent and four percent, respectively, over 2004. The retail gasoline offer is anchored by the On the Run-branded convenience stores and extensive chain of automatic car washes in addition to alliances with Tim Hortons, Royal Bank and Aeroplan.

The lubricants and specialities business holds the number-one market share in finished lubricants and further increased its market share in 2005. Operating costs remained best-in-class based on benchmarking data for comparable facilities.

Imperial remains a leader in the research and development of specialized lubricants and specialty products such as base oil and waxes. In 2005, Imperial's Sarnia Research Centre reformulated almost 270 of 500 lubricant products to meet changing market needs and commercialized 16 new products.

Capital investment in petroleum products totalled $478 million in 2005, a significant portion of which was directed to investments to produce ultra-low sulphur diesel and improve the environmental performance of the company's refineries. Projected capital expenditures in 2006 are expected to be about $350 million, primarily for continued investments in the ultra-low sulphur diesel project and to upgrade the retail service station network.

Refinery utilization
percent



Refinery utilization in 2005 averaged 93 percent – repeating the record rate achieved in 2004.

Esso and On the Run

Our goal is to provide customers with a leading retail offer through Esso retail outlets.

The company focuses on giving customers quick service in convenient locations with high-quality choices, including the one-stop shopping convenience of On the Run-branded convenience stores augmented with car-wash facilities, a Tim Hortons outlet and a Royal Bank automatic teller machine. At the end of 2005, 228 On the Run-branded stores included a Tim Hortons outlet, up from 200 in 2004. High-quality choices extend to the Esso customer loyalty programs as well. Program participants can opt for immediate rewards with Esso Extra points, such as car washes, or other rewards, such as travel and merchandise through the Aeroplan program. Customers can also choose how to pay at many locations. Pay-at-the-pump capability is in place for debit card, credit card or *Speedpass* transponder — the fastest and easiest way to pay. And in late 2005, Esso Gift Cards were introduced in a range of denominations, offering customers more choice.

Imperial has the leading retail share of gasoline sold in Canada, and the Esso-branded network of about 400 car-wash facilities remains the largest in the industry. The company is also the second-largest convenience retailer, with 600 convenience stores including 300 On the Run-branded stores across Canada.

Sales of the high-quality synthetic lubricant Mobil 1 are growing significantly faster than industry demand for synthetic motor oils in Canada.

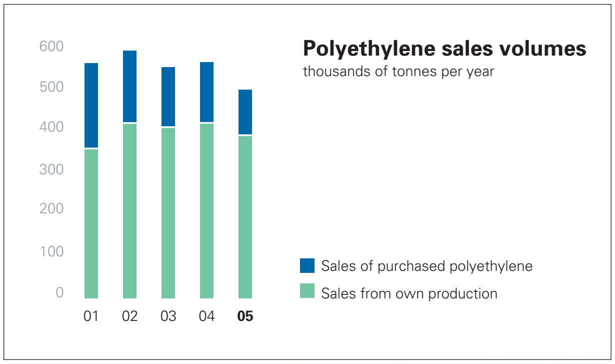
Trademarks:
- Mobil, On the Run and *Speedpass* are trademarks of Exxon Mobil Corporation or one of its subsidiaries.
- RBC and Royal Bank are registered trademarks of Royal Bank of Canada.
- Tim Hortons is a registered trademark of the TDL Group, Ltd.
- Aeroplan is a registered trademark of Aeroplan Limited Partnership.

Chemicals

Increasing the integration of the company's chemicals operations within existing refineries has been a focus for many years — reducing cost and maximizing the value for both operations. This strategy has proved effective in making the chemicals business a leader in cost and productivity within a cyclical business.

Chemicals at a glance

	2005	2004	2003	2002	2001
Net income (millions of dollars)	**121**	109	44	54	26
Cash flow from operating activities and asset sales (millions of dollars)	**94**	126	36	99	17
Chemical sales volumes (thousands of tonnes a day)	**3.0**	3.3	3.3	3.5	3.3
Capital employed at December 31 (millions of dollars)	**223**	225	233	160	196
Return on average capital employed (percent)	**54.0**	47.6	22.4	30.3	15.3



The company remains one of Canada's leading producers of petrochemical products, holding the largest market share in North America for polyethylene resins used for rotational molding, and the second-largest market share for resins used in injection molding. The chemicals business also has the largest share of the domestic fluids market, which includes the popular Esso-branded Varsol solvent.

In 2005, chemicals earnings were $121 million, up 11 percent from 2004, and cash flow from operating activities and asset sales was $94 million. Margins for two key products — polyethylene and benzene — were strong, driven by demand for end-use products and supported by a long-term industry rationalization in North America in these two segments. Total sales of petrochemical products were 3,000 tonnes a day, down from 2004 results, largely as a result of lower polyethylene sales.

Total polyethylene sales were down from 2004 as a result of a reduction in lower margin resales and weaker industry demand for polyethylene products. Despite running below capacity in 2005, the Sarnia polyethylene plant remains one of the most cost-competitive operations in North America today.

Varsol has been a household name in Canada for generations.

Principled people and practices

Imperial's board of directors toured the Strathcona refinery in 2005 and received an overview of control room operations.

Continued success as a leading provider of energy and petroleum products depends on earning and maintaining customers' confidence, as well as the larger public trust. This requires a strong commitment to integrity, sound business practices and disciplined financial management at all levels of the organization.

Corporate governance

Corporate governance practices meet the requirements of Canadian securities regulations, the Toronto Stock Exchange and the American Stock Exchange. They have also met the requirements of the U.S. Sarbanes-Oxley Act for the past three years, with minimal changes to corporate control procedures. This has largely been achieved through the Controls Integrity Management System, which covers all aspects of financial integrity. All business units conduct self-assessments against control criteria, and regular, rigorous audits are carried out by in-house and external auditors to test compliance.

The board of directors provides oversight to the company and its strategic plans. The majority of the board is comprised of independent, non-employee directors — and all board committees are made up solely of these directors.

Business ethics

All employees are required to comply with standards of business conduct, which address ethics, conflicts of interest, antitrust matters and directorships. Each year, company executives and other employees in controls-sensitive positions are required to confirm in writing that they are familiar with these standards. As well, managers are expected to regularly discuss with their staff the company's commitment to ethical standards and to provide guidance on these expectations.

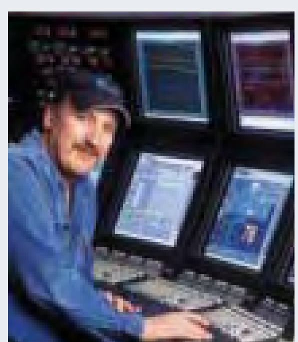
Sound financial reporting is fundamental to the model used to operate the business. Imperial has a straightforward capital structure and consistently reports results using transparent accounting practices. Special-purpose entities, special adjustments or pro forma reporting are not used. In addition, no derivatives to hedge or speculate on the future direction of commodity prices are used, nor is any production sold forward.

Workforce

The company is committed to building and maintaining a high-performing workforce that reflects the diversity of Canadian society. In 2005, 120 professional employees were hired who brought specialized skills to the business. Of this total, half were women and 14 percent were members of visible minorities. At year-end, Imperial's workforce included 5,096 employees.

The company offers a stimulating and challenging work environment that enhances personal growth. This commitment begins with potential future employees, by offering student co-op assignments in addition to alliances with trade and technical programs. Once hired, employees are involved in a process that provides a wide range of development opportunities, including job rotation, classroom learning, and performance feedback and mentoring, to enrich their skills and experience. In 2005, there were 1,130 attendees at the approximately 75 in-house courses offered across the company on topics with broad application, designed to help employees achieve their maximum potential. Employees were also provided with education programs specific to their professions.






From left to right:
A maintenance planner at the Strathcona refinery; a general mechanic repairing a valve at Nanticoke; a control room operator in the Mahkeses plant at Cold Lake; an industrial hygiene summer student measures noise levels at the Sarnia operation.

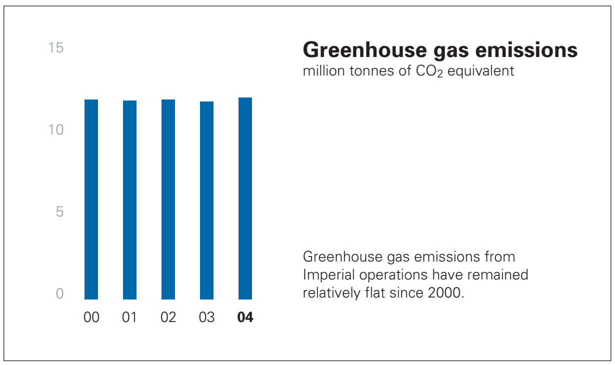
Caring for communities

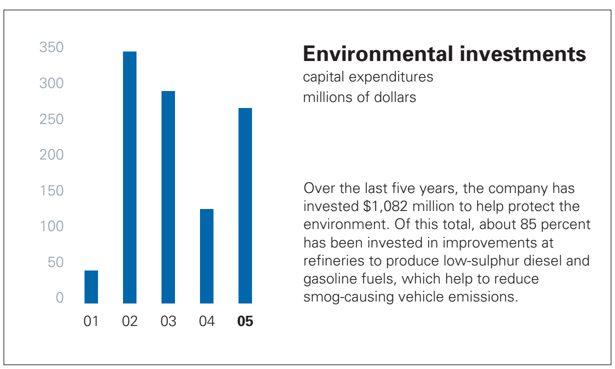
Since 1996, an education partnership between Imperial's Cold Lake operation and Grand Centre High School in Cold Lake, Alberta, has helped students gain employment and leadership skills.

As an industry leader, Imperial is dedicated to responsible operations everywhere it does business. The company exercises this responsibility by operating facilities safely, protecting workers and the environment, and investing in communities across Canada.

Management systems

The approach to workplace health, safety and environmental protection is defined by the Operations Integrity Management System (OIMS). This system fully meets the requirements of ISO (International Organization for Standardization) 14001 and has clearly defined expectations that every operation must follow. It also enables the company to track experiences and use those findings to fine-tune performance standards and results, enabling continuous improvement. Through OIMS, progress is measured, improvements planned, and management accountability ensured.





Workplace safety

The company strives for a workplace that supports the clear and simple objective that "Nobody Gets Hurt." The overriding belief is that all workplace injuries and illnesses are preventable. To that end, extensive safety programs have been established, which include workplace and management system assessments and a wide spectrum of training courses designed to enhance specific skills.

Supported by these programs, the company continued to be an industry leader in safety in 2005. Safety performance was the best on record for both employees and contractors. The rates of all workplace-related injuries and illnesses, including those that required time away from work, were lower than in any prior year.

Environmental performance

Under the pledge "Protect Tomorrow, Today," the objective is to continuously improve environmental performance at every stage of finding, developing and delivering energy. The goal is to drive operational incidents with environmental impact to zero.

Enhancements in recent years have strengthened the integration of environmental initiatives into the company's formal business planning and performance reviews. This rigorous environmental business planning process drives operating units to identify environmental objectives and targets, implement specific improvements and then measure and monitor the progress made in air and water quality.

During the year, this process and supporting systems helped lower the number of unintended releases from company-operated facilities to air, land and water. Additional improvement plans include projects to increase surveillance of pipelines and facilities, upgrade underground tankage and piping, and reduce the risk of spills into the St. Clair River from the Sarnia refinery's cooling water system.

The company continually looks for opportunities where it can achieve environmental goals while strengthening economic performance. In 2005, considerable time and effort were focused on improving energy efficiency in refineries and increasing the recovery of solution gas (natural gas associated with crude oil production). Since 1994, overall refining energy efficiency has improved by 16 percent. And at oil production properties, 99.9 percent of solution gas produced is recovered, which ranks among the best in the industry.

Imperial recognizes that the potential impact of greenhouse gas emissions on society and ecosystems may prove to be significant. To address these risks, the company is committed to improving energy efficiency and reducing greenhouse gas emissions from operations and from customer use of the company's products. These actions include reducing emissions today and investing in research into lower-emission technologies for tomorrow. Total greenhouse gas emissions from Imperial's operations in 2004 were close to 2000 levels, despite increases in throughput.

Community engagement

Imperial is committed to timely and meaningful engagement that helps address issues and increases understanding of community values, concerns and ideas. The company regularly meets with a wide range of stakeholders, including landowners, government officials, non-governmental organizations, Aboriginal leaders and local communities.

During 2005, the company actively consulted with community groups on its proposed Kearl oil sands project near Fort McMurray, Alberta. Consultation consisted of public open houses and dozens of smaller meetings with various stakeholders. These activities led to a better understanding of local traditional knowledge and identified potential project enhancements. The results of this effort were incorporated into the project design and applications filed with regulators in mid-2005.

To better understand local issues and concerns related to the Mackenzie gas project, active engagement with communities in the Northwest Territories continued. In 2005, about 320 documented consultation meetings were held with stakeholders in the North. Consultation has played an important role in project design and planning. Input from the public has resulted in changes to all aspects of the project, including alterations to the proposed pipeline route, relocation of facility and infrastructure sites, and adjustments to construction plans.

Community investment

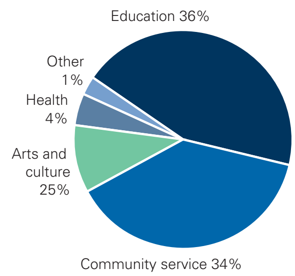
Corporate contributions play a key role in sustaining many non-profit organizations that provide needed services and enrich local quality of life. As a company with deep roots in Canada, these contributions are viewed not simply as a responsibility but essential to building strong communities.

In 2005, over $12 million was contributed to community initiatives through donations, sponsorships and other financial support. This was in addition to a special one-time corporate archives donation and endowment, valued at more than $3 million, to Calgary's Glenbow Museum. A number of regionally focused items from the archives collection were donated to the Saskatchewan Archives Board.

Imperial recognizes the positive impact made by United Way in communities and is proud to be a strong supporter.
In 2005, employees, annuitants and the company donated more than $3 million to United Way–Centraide campaigns across Canada. The 2005 United Way campaign involved numerous innovative activities coast-to-coast, including the Esso United Way Day in September. This day saw 450 Esso retail sites across Canada donating one cent to United Way for every litre of fuel sold, as well as customers making their own donations.

The company also responded to the needs of international communities devastated by natural events in 2005. Employees and annuitants gave generously to the Canadian Red Cross to support hurricane relief efforts along the U.S. Gulf Coast. Imperial also donated a total of $250,000 to support these efforts.

Community investment



In 2005, about 36 percent of Imperial's charitable contributions were directed to educational organizations and initiatives. By supporting education, the company's objective is to help contribute to the economic future of communities.

A potential remediation tool for salt-impacted sites is using naturally occurring halophytes, or "salt-loving plants," which extract salt from soil.

Research is vital to improving environmental performance

Imperial is committed to developing technologies to create new and better ways to improve environmental performance. For example, studies at the company's Calgary research facility led to improvements in water-treatment operations that reduced chemical consumption while improving energy efficiency. Research also brought about a new pad design for Cold Lake operations that reduces the surface disturbance of a pad by 20 percent, and research work continues in the use of vegetation to remove salt contaminants from soil. At the Sarnia Research Centre, new technology was developed to remove sulphur accumulated during pipeline transport. It enables low-sulphur fuels from the Strathcona refinery to run through a joint crude oil and products pipeline to the West Coast. Research at Sarnia also led to new lubricants for passenger cars that reduce engine friction to provide better fuel economy.

As Canada's oil sands enter a phase of accelerated long-term growth, the importance of research and technology in improving air and water quality and in controlling greenhouse gas emissions will continue to be important. Innovative technologies will be required to counter the emissions created through continued oil sands development. In 2005, the company continued its five-year, $10-million funding commitment to the Imperial Oil Centre for Oil Sands Innovation at the University of Alberta. The centre's mandate includes finding environmentally responsible methods to further develop Canada's oil sands resources. It is another example of the company's commitment to using research and technology to improve environmental performance.

Financial section

Financial summary (U.S. GAAP)

millions of dollars	**2005**	2004	2003	2002	2001
Total operating revenues	**27 797**	22 408	19 094	16 890	17 153
Net income by segment:					
Natural resources	**2 008**	1 517	1 174	1 052	953
Petroleum products	**694**	556	462	147	376
Chemicals	**121**	109	44	54	26
Corporate and other	**(223)**	(130)	25	(39)	(132)
Net income	**2 600**	2 052	1 705	1 214	1 223
Total assets	**15 582**	14 027	12 337	12 003	10 888
Long-term debt	**863**	367	859	1 466	1 029
Total debt	**1 439**	1 443	1 432	1 538	1 489
Other long-term obligations	**1 728**	1 525	1 314	1 822	1 303
Capital employed	**8 131**	7 821	7 029	6 498	5 784
Cash flow from operating activities and asset sales	**3 891**	3 414	2 283	1 749	2 050
Per-share information (dollars)					
Net income per share – basic	**7.62**	5.75	4.58	3.20	3.11
Net income per share – diluted	**7.59**	5.74	4.58	3.20	3.11
Dividends	**0.94**	0.88	0.87	0.84	0.83

Management's discussion and analysis of financial condition and results of operations

Overview

The following discussion and analysis of Imperial's financial results, as well as the accompanying financial statements and related notes to consolidated financial statements to which they refer, are the responsibility of the management of Imperial Oil Limited. Beginning in 2004, the company reported its financial results based on generally accepted accounting principles (GAAP) in the United States. The differences between U.S. and Canadian GAAP are small for Imperial and an explanation of them as they apply to the company, including a tabular reconciliation of net income reported under U.S. GAAP and under Canadian GAAP, is included as a note to the financial statements on page 58. Supplemental financial information based on Canadian GAAP pertaining to management's discussion and analysis of Imperial's financial results is also provided, on page 34.

The company's accounting and financial reporting fairly reflect its straightforward business model involving the extracting, refining and marketing of hydrocarbons and hydrocarbon-based products. The company's business involves the production (or purchase), manufacture and sale of physical products, and all commercial activities are directly in support of the underlying physical movement of goods.

With its extensive resource base in Canada, financial strength, disciplined investment approach and technology portfolio, Imperial is well positioned to participate in substantial investments to develop new energy supplies. While commodity prices remain volatile on a short-term basis depending upon supply and demand, Imperial's investment decisions are based on long-term outlooks, using a disciplined approach in selecting and pursuing the most attractive investment opportunities. The corporate plan is a fundamental annual management process that is the basis for setting near-term operating and capital objectives in addition to providing the longer-term economic assumptions used for investment evaluation purposes. Annual plan volumes are based on individual field production profiles that are updated annually. Prices for crude oil, natural gas and refined products used for investment evaluation purposes are based on corporate plan assumptions that are developed annually. Potential investment opportunities are tested over a wide range of economic scenarios to establish the resiliency of each opportunity. Once investments are made, a reappraisal process is completed to ensure relevant lessons are learned and improvements are incorporated into future projects. Imperial views return on capital employed as the best measure of historical capital productivity.

Business environment and outlook

Natural resources

Imperial produces crude oil and natural gas for sale into large North American markets. Economic and population growth are expected to remain the primary drivers of energy demand. The company expects the global economy to grow at an average rate of almost three percent per year through 2030. World energy demand should grow by about two percent per year, and oil and gas are expected to consistently account for about 60 percent of world energy supply through 2030. Over the same period, the Canadian economy is expected to grow at an average rate of about two percent per year, and Canadian demand for energy at a rate of about one percent per year. Oil and gas are expected to continue to supply two-thirds of Canadian energy demand. It is expected that Canada will also be a growing supplier of energy to U.S. markets through this period.

Oil products are the transportation fuel of choice for the world's fleet of cars, trucks, trains, ships and airplanes. Primarily because of increased demand in developing countries, oil consumption will increase by 35 percent or about 30 million barrels a day by 2030. Canada's oil sands represent an important additional source of supply.

Natural gas is expected to be a major primary energy source globally, capturing about one-third of all incremental energy growth and approaching one-quarter of global energy supplies. Natural gas production from mature established regions in the United States and Canada is not expected to meet increasing demand, strengthening the market opportunities for new gas supply from Canada's frontier areas.

Crude oil and natural gas prices are determined by global and North American markets and are subject to changing supply and demand conditions. These can be influenced by a wide range of factors, including economic conditions, international political developments and weather. In the past, crude oil and natural gas prices have been volatile, and the company expects that volatility to continue.

Imperial has a large and diverse portfolio of oil and gas resources in Canada, both developed and undeveloped, which helps reduce the risks of dependence on potentially limited supply sources in the upstream. With the relative maturity of conventional production in the established producing areas of Western Canada, Imperial's production is expected to come increasingly from frontier and unconventional sources, particularly oil sands and natural gas from the Far North, where Imperial has large undeveloped resource opportunities.

Petroleum products

The downstream continues to experience ongoing volatility in industry margins. Refining margins are the difference between what a refinery pays for its raw materials (primarily crude oil) and the wholesale prices it receives for the range of products produced (primarily gasoline, diesel fuel, heating oil, jet fuel and fuel oil). Crude oil and many products are widely traded with published international prices. Prices for those commodities are determined by the marketplace, often an international marketplace, and are affected by many factors, including global and regional supply/demand balances, inventory levels, refinery operations, import/export balances, transportation logistics, seasonality and weather. Canadian wholesale prices in particular are largely determined by wholesale prices in adjacent U.S. regions. These prices and factors are continually monitored and provide input to operating decisions about which raw materials to buy, facilities to operate and products to make. However, there are no reliable indicators of future market factors that accurately predict changes in margins from period to period.

Imperial's downstream strategies are to provide customers with quality service at the lowest total cost offer, have the lowest net unit costs among our competitors, ensure efficient and effective use of capital and capitalize on integration with the company's other businesses. Imperial owns and operates four refineries in Canada, with distillation capacity of 502,000 barrels a day and lubricant manufacturing capacity of 9,000 barrels a day.

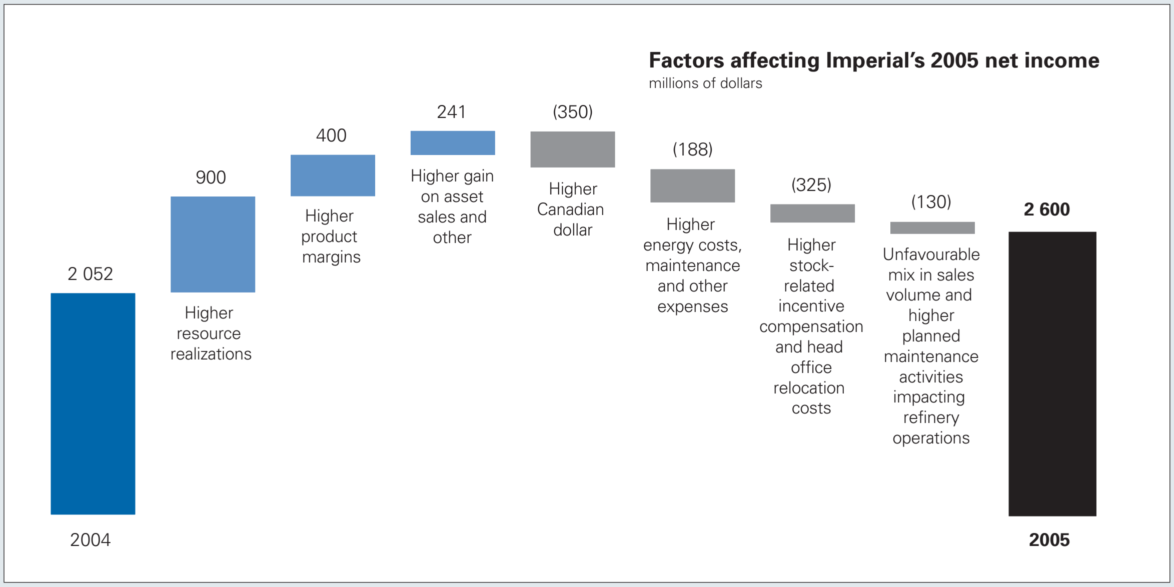
Imperial's fuels marketing business includes retail operations across Canada serving customers through about 2,000 Esso-branded service stations, of which about 700 are company-owned or leased, and wholesale and industrial operations through a network of 30 primary distribution terminals.

Chemicals

Although the current business environment is favourable, the North American petrochemical industry is cyclical. The company's strategy for its chemicals business is to reduce costs and maximize value by continuing to increase the integration of its chemicals plants at Sarnia and Dartmouth with the refineries. The company also benefits from its integration within ExxonMobil's North American chemicals businesses, enabling Imperial to maintain a leadership position in its key market segments.

Results of operations

Net income in 2005 was $2,600 million or $7.59 a share – the best year on record – surpassing the previous record of $2,052 million or $5.74 a share in 2004 (2003 – $1,705 million or $4.58 a share). Strong operational performance in 2005 allowed the company to capture opportunities in an environment of higher commodity prices and industry margins. Higher realizations for crude oil, natural gas and Cold Lake bitumen and stronger refining margins contributed about $1,300 million to earnings when compared to 2004. Also positive to earnings was increased natural gas and Cold Lake bitumen volumes of about $125 million. These factors were partly offset by a stronger Canadian dollar, lower volumes at Syncrude, the natural decline of conventional crude oil volumes and higher planned maintenance impacting refinery operations. These factors had a combined negative impact of about $590 million on earnings. Operating costs increased and impacted earnings by about $325 million, primarily driven by higher energy costs and higher Syncrude maintenance expenses. In addition, stock-related compensation expenses were $143 million higher than a year earlier and costs associated with the head office relocation of about $45 million were incurred in 2005. Included in net income in 2005 was a $233 million gain on sale of assets, mainly from the Redwater and North Pembina fields. Included in net income in 2004 was a $32 million gain on sale of assets and a write down of $42 million on a north Toronto property.



Total operating revenues were $27.8 billion, up 24 percent from 2004.

The return on average capital employed was 33 percent, compared with 28 percent in 2004 (2003 – 25 percent).

Beginning in the third quarter of 2005, incentive compensation expenses previously included in the operating segments are now reported in the "corporate and other" segment. This change has the effect of isolating in one segment all incentive compensation expenses and improving the transparency of operating events in the operating segments. This change has no impact on consolidated total expenses, net income or the cash-flow profile of the company. Segmented results in 2005, 2004 and 2003 have been reclassified for comparative purposes.

Natural resources

Net income from natural resources was a record $2,008 million, exceeding the previous record achieved in 2004 of $1,517 million (2003 – $1,174 million). Improved realizations for crude oil, natural gas and Cold Lake bitumen of about $910 million, and higher natural gas and Cold Lake bitumen volumes of about $125 million were the main reasons for the increase. Their positive impact on earnings was partially offset by the unfavourable impact of a higher Canadian dollar of about $260 million, lower volumes due to higher maintenance activities at Syncrude of about $100 million, and the natural decline of conventional crude oil and NGL volumes of about $90 million. Operating costs were also higher than 2004 by about $275 million, primarily driven by higher energy costs of about $140 million and higher Syncrude maintenance and other expenses of about $75 million. Included in net income in 2005 was a $208 million gain on sale of assets, mainly from the Redwater and North Pembina fields. Included in net income in 2004 was a $25 million gain on sale of assets.

Resource operating revenues were $8.2 billion, up from $6.6 billion in 2004 (2003 – $5.6 billion). The main reasons for the increase were higher realizations primarily for crude oil, natural gas and Cold Lake bitumen and higher natural gas and Cold Lake bitumen volumes.

Return on average capital employed was 53 percent for the natural resources segment, compared with 40 percent in 2004 (2003 – 34 percent), reflecting higher net income.

Financial statistics

millions of dollars	**2005**	2004	2003	2002	2001
Net income	**2 008**	1 517	1 174	1 052	953
Operating revenues	**8 189**	6 580	5 584	4 790	5 310
Cash flow from operating activities and asset sales	**2 805**	2 395	1 729	1 276	1 248
Capital employed at December 31	**3 778**	3 870	3 744	3 265	2 586
Return on average capital employed (percent)	**52.5**	39.8	33.5	36.0	40.0

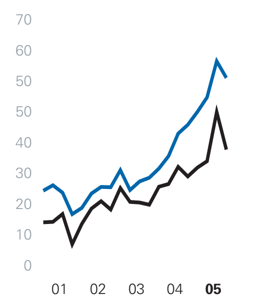
U.S.-dollar world oil prices were considerably higher in 2005 than in the previous year. The annual average price of Brent crude oil, the most actively traded North Sea crude and a common benchmark of world oil markets, was about $55 (U.S.) a barrel in 2005, a more than 42 percent increase over the average price of $38 in 2004 (2003 – $29). However, the company's Canadian-dollar realizations for conventional crude oil increased to a lesser extent because of a stronger Canadian dollar. Average realizations for conventional crude oil during the year were $64.48 (Cdn) a barrel, an increase of 32 percent from $48.96 in 2004 (2003 – $40.10).

Average prices for Canadian heavy crude oil were higher in 2005, but by less than the relative increase in light crude oil prices, as increased supply of heavy crude oil widened the average spread between light and heavy crude. The price of Bow River, a benchmark Canadian heavy crude oil, was higher by 20 percent in 2005, much less than the increase in prices for Canadian light crude oil.

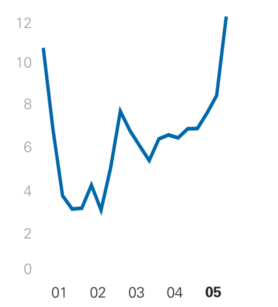
Prices for Canadian natural gas in 2005 were higher than the previous year. The average of 30-day spot prices for natural gas at the AECO hub in Alberta was about $9.01 a thousand cubic feet in 2005, compared with $6.80 in 2004 (2003 – $6.70). The company's average realizations on natural gas sales were $9 a thousand cubic feet, compared with $6.78 in 2004 (2003 – $6.60).

Average realizations and prices

Canadian dollars	**2005**	2004	2003	2002	2001
Conventional crude oil realizations (a barrel)	**64.48**	48.96	40.10	36.81	35.56
Natural gas liquids realizations (a barrel)	**40.00**	33.78	32.09	23.38	29.31
Natural gas realizations (a thousand cubic feet)	**9.00**	6.78	6.60	4.02	5.72
Par crude oil price at Edmonton (a barrel)	**69.86**	53.26	43.93	40.44	39.64
Heavy crude oil price at Hardisty (Bow River, a barrel)	**45.62**	37.98	33.00	31.85	25.11



Crude oil prices
U.S. dollars a barrel – quarterly average



Natural gas average prices
Canadian dollars a thousand cubic feet – AECO hub 30-day spot

Total gross production of crude oil and NGLs averaged 261,000 barrels a day, compared with 262,000 barrels in 2004 (2003 – 256,000).

Gross bitumen production at the company's wholly owned facilities at Cold Lake was a record 139,000 barrels a day, up from 126,000 barrels in 2004 (2003 – 129,000), due to the cyclic nature of production at Cold Lake and increased volumes from the ongoing development drilling program.

Production from the Syncrude operation, in which the company has a 25 percent interest, was lower during 2005 as a result of planned and unplanned maintenance activities. Gross production of upgraded crude oil decreased to 214,000 barrels a day from 238,000 barrels in 2004 (2003 – 211,000). Imperial's share of average gross production decreased to 53,000 barrels a day from 60,000 barrels in 2004 (2003 – 53,000).

Gross production of conventional oil decreased to 38,000 barrels a day from 43,000 barrels in 2004 (2003 – 46,000) as a result of the natural decline in Western Canadian reservoirs.

Gross production of NGLs available for sale averaged 31,000 barrels a day in 2005, down from 33,000 barrels in 2004 (2003 – 28,000), mainly due to the declining content of Wizard Lake gas production.

Gross production of natural gas increased to 580 million cubic feet a day from 569 million in 2004 (2003 – 513 million). The increased volumes were mainly due to higher production from the Nisku, Wizard Lake and Medicine Hat fields.

In December, the company sold its wholly owned and operated Redwater field as well as interests in the North Pembina field, both located in Alberta, for net proceeds of $289 million, realizing a gain of $163 million. Oil and natural gas production for the company's share of these two properties averaged approximately 4,370 oil-equivalent barrels a day during the third quarter of 2005.

Crude oil and NGLs – production and sales (a)

thousands of barrels a day	**2005**		2004		2003		2002		2001	
	gross	net	gross	net	gross	net	gross	net	gross	net
Cold Lake	**139**	**124**	126	112	129	116	112	106	128	121
Syncrude	**53**	**53**	60	59	53	52	57	57	56	52
Conventional crude oil	**38**	**29**	43	33	46	35	51	39	55	42
Total crude oil production	**230**	**206**	229	204	228	203	220	202	239	215
NGLs available for sale	**31**	**25**	33	26	28	22	27	21	28	22
Total crude oil and NGL production	**261**	**231**	262	230	256	225	247	223	267	237
Cold Lake sales, include diluent (b)	**183**		167		170		145		167	
NGL sales	**39**		42		39		40		43	

Natural gas – production and sales (a)

millions of cubic feet a day	**2005**		2004		2003		2002		2001	
	gross	net	gross	net	gross	net	gross	net	gross	net
Production (c)	**580**	**514**	569	518	513	457	530	463	572	466
Sales	**536**		520		460		499		502	

(a) Daily volumes are calculated by dividing total volumes for the year by the number of days in the year. Gross production is the company's share of production (excluding purchases) before deducting the share of mineral owners or governments or both. Net production excludes those shares.

(b) Includes natural gas condensate added to the Cold Lake bitumen to facilitate transportation to market by pipeline.

(c) Production of natural gas includes amounts used for internal consumption with the exception of the amounts reinjected.

Operating costs increased by 17 percent in 2005. The main factors were higher energy costs and higher Syncrude maintenance and other expenses.

Effective April 1, 2005, the company and an affiliate of Exxon Mobil Corporation in Canada agreed to operate their respective Western Canada production organizations as one single organization. Under the consolidation, Imperial will operate all Western Canada properties. There are no asset ownership changes. The consolidation is expected to result in efficiencies from a streamlined organization.

Petroleum products

Net income from petroleum products was a record $694 million or 2.1 cents a litre in 2005, improving on the previous record of $556 million or 1.7 cents a litre in 2004 (2003 – $462 million or 1.5 cents a litre). Higher earnings in 2005 were mainly a result of stronger industry refining margins. Marketing margins in 2005 remained at the low levels of 2004. Planned refinery maintenance activities were higher in the year, when compared to 2004, impacting both refinery operations and expenses and reducing earnings by about $75 million. Higher earnings were also partially offset by a stronger Canadian dollar of about $85 million, higher energy costs of about $65 million and costs associated with the head office relocation of about $35 million.

Operating revenues were $24 billion, up from $19.2 billion in 2004 (2003 – $16 billion).

Return on average capital employed was 27 percent for the petroleum products segment, compared with 21 percent in 2004 (2003 – 18 percent).

Financial statistics

millions of dollars	**2005**	2004	2003	2002	2001
Net income	**694**	556	462	147	376
Operating revenues	**24 017**	19 169	16 004	14 400	14 379
Cash flow from operating activities and asset sales	**874**	946	706	448	882
Capital employed at December 31	**2 642**	2 524	2 707	2 334	2 164
Return on average capital employed (percent)	**26.9**	21.3	18.3	6.5	16.7

Sales of petroleum products

millions of litres a day (a)	**2005**	2004	2003	2002	2001
Gasolines	**33.4**	33.2	33.0	32.9	32.3
Heating, diesel and jet fuels	**26.9**	27.3	26.2	25.0	26.5
Heavy fuel oils	**6.0**	5.9	5.4	4.9	5.4
Lube oils and other products	**7.6**	7.0	5.8	6.4	5.4
Net petroleum product sales	**73.9**	73.4	70.4	69.2	69.6
Sales under purchase and sale agreements	**15.2**	14.2	14.6	13.9	11.6
Total sales of petroleum products	**89.1**	87.6	85.0	83.1	81.2
Total domestic sales of petroleum products (percent)	**93.8**	93.0	93.3	91.5	93.4

(a) Volumes a day are calculated by dividing total volumes for the year by the number of days in the year.

Refinery utilization

millions of litres a day (a)	**2005**	2004	2003	2002	2001
Total refinery throughput (b)	**74.1**	74.3	71.6	71.2	71.4
Refinery capacity at December 31	**79.9**	79.9	79.9	79.4	79.1
Utilization of total refinery capacity (percent)	**93**	93	90	90	90

(a) Volumes a day are calculated by dividing total volumes for the year by the number of days in the year.

(b) Crude oil and feedstocks sent directly to atmospheric distillation units.

One thousand litres is approximately 6.3 barrels.

Margins were stronger in the refining segment of the industry in 2005 compared with those in 2004, pushed up by increased demand for refined petroleum products that stemmed from generally stronger global economic conditions and the short-term production disruptions along the U.S. Gulf Coast. However, the effects of stronger industry margins were reduced partially by a higher Canadian dollar. Marketing margins in 2005 remained at the low levels of 2004, reflecting the impact of highly competitive markets.

Operating performance of the company's four refineries was solid. Despite higher planned maintenance, refinery utilization for 2005 was 93 percent, repeating a record performance level that was established in 2004 (2003 – 90 percent).

The company's total sales volumes, including those resulting from reciprocal supply agreements with other companies, were 89.1 million litres a day, compared with 87.6 million litres in 2004 (2003 – 85 million). Excluding sales resulting from reciprocal agreements, sales were 73.9 million litres a day, compared with 73.4 million litres in 2004 (2003 – 70.4 million).

Operating costs increased by about seven percent in 2005 from the previous year, mainly because of higher energy costs and costs associated with the head office relocation.

In 2005, the company divested its Western Canada fertilizer distribution assets to Agrium Inc. The transaction did not have a material impact on the financial results of the petroleum products segment.

Chemicals

Net income from chemicals operations was $121 million in 2005, compared with $109 million in 2004 (2003 – $44 million). Improved industry margins were partly offset by weaker industry demand for polyethylene products.

Financial statistics

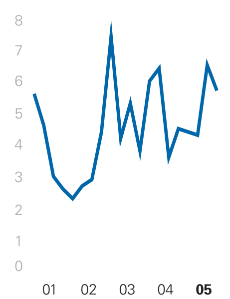
millions of dollars	**2005**	2004	2003	2002	2001
Net income	**121**	109	44	54	26
Operating revenues	**1 665**	1 509	1 232	1 164	1 175
Cash flow from operating activities and asset sales	**94**	126	36	99	17
Capital employed at December 31	**223**	225	233	160	196
Return on average capital employed (percent)	**54.0**	47.6	22.4	30.3	15.3

Sales volumes

thousands of tonnes a day (a)	**2005**	2004	2003	2002	2001
Polymers and basic chemicals	**2.1**	2.4	2.4	2.5	2.4
Intermediate and others	**0.9**	0.9	0.9	1.0	0.9
Total chemicals	**3.0**	3.3	3.3	3.5	3.3

(a) Volumes a day are calculated by dividing total volumes for the year by the number of days in the year.

One tonne is approximately 1.1 short tons or 0.98 long tons.



Average refining margins
Canadian cents a litre

New York Harbor product prices minus Brent crude; reflects Imperial's product mix.

Total operating revenues from chemical operations were $1,665 million, compared with $1,509 million in 2004 (2003 – $1,232 million). Higher prices for polyethylene and intermediate chemicals were the main contributing factors.

Return on average capital employed was 54 percent for the chemicals segment, compared with 48 percent in 2004 (2003 – 22 percent).

The average industry price of polyethylene was $1,708 a tonne in 2005, up eight percent from $1,584 a tonne in 2004 (2003 – $1,415).

Sales of chemicals were 3,000 tonnes a day, compared with 3,300 tonnes a day in 2004 (2003 – 3,300 tonnes) mainly due to a reduction in lower margin polyethylene resale volumes and weaker industry demand for polyethylene products.

Operating costs in the chemicals segment for 2005 were about four percent higher than 2004. Higher energy costs were the main reason for the increase.

Corporate and other

Net income from corporate and other was negative $223 million in 2005, compared with negative $130 million in 2004 (2003 – positive $25 million). Lower net income in 2005 was mainly due to higher stock-related compensation expenses of about $143 million, largely driven by the increase in the company's share price from a year earlier, partially offset by the absence of a write down of $42 million on a north Toronto property previously recorded in 2004.

Liquidity and capital resources

Sources and uses of cash

millions of dollars	**2005**	2004
Cash provided by/(used in)		
Operating activities	**3 451**	3 312
Investing activities	**(992)**	(1 306)
Financing activities	**(2 077)**	(1 175)
Increase/(decrease) in cash and cash equivalents	**382**	831
Cash and cash equivalents at end of year	**1 661**	1 279

Although the company issues long-term debt from time to time, internally generated funds cover the majority of its financial requirements. The management of cash that may be temporarily available as surplus to the company's immediate needs is carefully controlled, both to ensure that it is secure and readily available to meet the company's cash requirements as they arise and to optimize returns on cash balances.

Cash flows from operating activities are highly dependent on crude oil and natural gas prices and product margins. In addition, the company will need to continually find and develop new resources, and continue to develop and apply new technologies and recovery processes to existing fields, in order to maintain or increase production and resulting cash flows in future periods. Projects are in place or underway to increase production capacity. However, these volume increases are subject to a variety of risks, including project execution, operational outages, reservoir performance and regulatory changes.

The company's financial strength enables it to make large, long-term capital expenditures. Imperial's large and diverse portfolio of development opportunities and the complementary nature of its business segments help mitigate the overall risks of the company and associated cash flow. Further, due to its financial strength, debt capacity and diverse portfolio of opportunities, the risk associated with failure or delay of any single project would not have a significant impact on the company's liquidity or ability to generate sufficient cash flows for its operations and fixed commitments.

Cash flow from operating activities

Cash provided by operating activities was $3,451 million, versus $3,312 million in 2004 (2003 – $2,227 million). The increased cash flow was mainly due to higher net income and the impact of higher commodity prices on working capital partially offset by additional funding contributions to the employee pension plan and the timing of income tax payments. The $233 million gain on asset sales is a non-cash item and represented a reduction from net income in the cash from operating activities category. The cash received from asset sales is reported in cash from investing activities.

Capital and exploration expenditures

Total capital and exploration expenditures were $1,475 million in 2005, up from $1,445 million in 2004 (2003 – $1,559 million).

The funds were used mainly to invest in Syncrude and Cold Lake to maintain and expand production capacity, upgrade refineries to meet low-sulphur diesel requirements, improve operating efficiency and upgrade the network of Esso retail outlets. About $280 million was spent on projects related to reducing the environmental impact of its operations and improving safety, including about $240 million on the $500-million capital project to produce low-sulphur diesel.

The following table shows the company's capital and exploration expenditures for natural resources during the five years ending December 31, 2005:

millions of dollars	**2005**	2004	2003	2002	2001
Exploration	**43**	60	57	39	49
Production	**232**	234	181	143	109
Heavy oil	**662**	819	769	804	588
Total capital and exploration expenditures	**937**	1 113	1 007	986	746

For the natural resources segment, about 90 percent of the capital and exploration expenditures in 2005 was focused on growth opportunities. The single largest investment during the year was the company's share of the Syncrude expansion. Construction on the upgrader expansion portion of the Syncrude Stage 3 project was about 98 percent complete at the end of 2005 with remaining activities principally focused on mechanical completion, testing and commissioning. Completion of the project with production of higher quality synthetic crude oil is scheduled to come on stream by mid-2006. Continuing cost and labour pressures in the Fort McMurray area have resulted in the total projected cost for the Stage 3 project growing from $7.8 billion, indicated in March 2004, to $8.4 billion currently. The remainder of 2005 investment was directed to drilling at Cold Lake and conventional fields in Western Canada and advancing the Mackenzie gas project.

In April 2005, the company, on behalf of the Mackenzie gas project co-venturers, halted project execution activities due to insufficient progress on areas critical to the project – the finalization of benefits and access agreements, the establishment of a clear regulatory process and appropriate fiscal terms for the project. Sufficient advances were subsequently made in these areas and, in November, the company notified the National Energy Board of the project proponents' readiness to proceed to public hearings on the project. Hearings began in January 2006 and are expected to continue through 2006. During 2005, initial applications for fieldwork approvals, including land-use permits and water licences, were filed with regulatory agencies and boards. Additional permit applications will be filed in 2006.

In July 2005, regulatory applications for the development of the Kearl oil sands project, in which Imperial holds about a 70 percent interest and would act as operator in a joint venture with ExxonMobil Canada, were filed with the Alberta Energy and Utilities Board and Alberta Environment. Hearings are expected to begin later in 2006.

During the third quarter of 2005, the company and its partners completed a second 3-D seismic acquisition program in the Orphan Basin on Canada's East Coast. A contract agreement for a drilling vessel has been signed and exploration drilling in the Orphan Basin, offshore Newfoundland is expected in mid-2006. The company holds a 15 percent interest in the eight deepwater exploration licences in the Orphan Basin.

Planned capital and exploration expenditures in natural resources are expected to be about $800 million in 2006, with over 80 percent of the total focused on growth opportunities. Investments are mainly planned for development drilling at Cold Lake and conventional oil and gas operations in Western Canada, facilities improvement at Syncrude, and the Mackenzie gas project.

The following table shows the company's capital expenditures in the petroleum products segment during the five years ending December 31, 2005:

millions of dollars	**2005**	2004	2003	2002	2001
Marketing	**91**	85	91	133	171
Refining and supply	**368**	178	369	399	118
Other (a)	**19**	20	18	57	50
Total capital expenditures	**478**	283	478	589	339

(a) Consists primarily of real estate purchases.

For the petroleum products segment, capital expenditures increased to $478 million in 2005, compared with $283 million in 2004 (2003 – $478 million). The company invested about $240 million in refining operations and other facilities during the year as part of a three-year, $500-million project to reduce sulphur content in diesel. In addition, more than $100 million was spent on other refinery projects to improve energy efficiency and increase yield. Major investments were also made to upgrade the network of Esso service stations during the year.

Capital expenditures for the petroleum products segment in 2006 are expected to be about $350 million. Major items include additional investment in refining facilities to complete the sulphur-reduction project and continued enhancements to the company's retail network.

The following table shows the company's capital expenditures for its chemicals operations during the five years ending December 31, 2005:

millions of dollars	**2005**	2004	2003	2002	2001
Capital expenditures	**19**	15	41	25	30

Of the capital expenditures for chemicals in 2005, the major investment focused on improving energy efficiency, yields and process control technology.

Planned capital expenditures for chemicals in 2006 will be about $15 million.

Total capital and exploration expenditures for the company in 2006, which will focus mainly on growth and productivity improvements, are expected to total about $1.2 billion and will be financed from internally generated funds.

Cash flow from financing activities

In June, the company renewed the normal course issuer bid (share-repurchase program) for another 12 months. During 2005, the company purchased about 17.5 million shares for $1,795 million (2004 – 14 million shares for $872 million). Since Imperial initiated its first share-repurchase program in 1995, the company has purchased 250 million shares – representing about 43 percent of the total outstanding at the start of the program – with resulting distributions to shareholders in excess of $8.6 billion.

The company declared dividends totalling 94 cents a share in 2005, up from 88 cents in 2004 (2003 – 87 cents). Regular annual per-share dividends paid have increased in each of the past 11 years and, since 1986, payments per share have grown by more than 76 percent.

Total debt outstanding at the end of 2005, excluding the company's share of equity company debt, was $1,439 million, compared with $1,443 million at the end of 2004 (2003 – $1,432 million). Debt represented 18 percent of the company's capital structure at the end of 2005, compared with 19 percent at the end of 2004 (2003 – 21 percent).

Debt-related interest incurred in 2005, before capitalization of interest, was $45 million, up from $37 million in 2004 (2003 – $38 million). The average effective interest rate on the company's debt was 3.1 percent in 2005, compared with 2.8 percent in 2004 (2003 – 2.9 percent).

During 2005, the company's Canadian-dollar variable-rate loans of $500 million and $318 million from Exxon Overseas Corporation, due in 2005 and 2006, were extended to mature in 2007 and 2008, respectively.

Financial percentages, ratios and credit rating

	2005	2004	2003	2002	2001
Total debt as a percentage of capital (a)	**18**	19	21	24	26
Interest coverage ratios					
Earnings basis (b)	**88**	83	64	46	26
Cash-flow basis (c)	**101**	108	80	63	36
Long-term unsecured debt rating					
Local currency (DBRS/S&P) (d)	**AA/AAA**	AA/AAA	AA/AAA	AA/AAA	AA/AAA

(a) Current and long-term portions of debt (page 40), divided by debt and shareholders' equity (page 40).

(b) Net income (page 38), debt-related interest before capitalization (page 57, note 14) and income taxes (page 38) divided by debt-related interest before capitalization.

(c) Cash flow from net income adjusted for the cumulative effect of accounting change and other non-cash items (page 39), current income tax expense (page 48, note 4) and debt-related interest before capitalization (page 57, note 14) divided by debt-related interest before capitalization.

(d) Dominion Bond Rating Service (DBRS) and Standard & Poor's Corporation (S&P) are debt-rating agencies.

The company's financial strength, as evidenced by the above financial ratios, represents a competitive advantage of strategic importance. The company's sound financial position gives it the opportunity to access capital markets in the full range of market conditions and enables the company to take on large, long-term capital commitments in the pursuit of maximizing shareholder value.

On February 2, 2006, the company proposed to subdivide the common shares of the company on a three-for-one basis. The proposed stock split is subject to shareholder and regulatory approvals.

Contractual obligations

The following table shows the company's contractual obligations outstanding at December 31, 2005. It brings together, for easier reference, data from the consolidated balance sheet and from individual notes to the consolidated financial statements.

millions of dollars	Financial statement note reference	Payment due by period 2006	2007 to 2010	2011 and beyond	Total amount
Long-term debt and capital leases	Note 3	477	833	30	1 340
Imperial's share of equity company debt		59	–	–	59
Operating leases	Note 11	48	168	57	273
Unconditional purchase obligations (a)	Note 11	94	145	20	259
Firm capital commitments (b)	Note 11	196	36	–	232
Pension obligations (c)	Note 6	416	80	346	842
Asset retirement obligations (d)	Note 7	36	141	190	367
Other long-term agreements (e)	Note 11	403	1 022	356	1 781

(a) Unconditional purchase obligations mainly pertain to pipeline throughput agreements.

(b) Firm capital commitments related to capital projects, shown on an undiscounted basis, totalled approximately $232 million at the end of 2005, compared to $171 million at year-end 2004. The largest commitment outstanding at year-end 2005 was associated with the company's share of upstream capital projects of $72 million offshore Canada's East Coast.

(c) The amount by which accumulated benefit obligations (ABO) exceeded the fair value of fund assets at year-end (page 49, note 6). For funded pension plans, this difference was $489 million at December 31, 2005. For unfunded plans, this was the ABO amount of $353 million. The payments by period include expected contributions to funded pension plans in 2006 and estimated benefit payments for unfunded plans in all years.

(d) Asset retirement obligations represent the discounted present value of legal obligations associated with site restoration on the retirement of assets with determinable useful lives.

(e) Other long-term agreements include primarily raw material supply and transportation services agreements.

The company was contingently liable at December 31, 2005 for a maximum of $77 million relating to guarantees for purchasing operating equipment and other assets from its rural marketing associates upon expiry of the associate agreement or the resignation of the associate. The company expects that the fair value of the operating equipment and other assets so purchased would cover the maximum potential amount of future payments under the guarantees.

Various lawsuits are pending against Imperial Oil Limited and its subsidiaries. Based on a consideration of all relevant facts and circumstances, the company does not believe the ultimate outcome of any currently pending lawsuits against the company will have a material adverse effect on the company's operations or financial condition. There are no events or uncertainties known to management beyond those already included in reported financial information that would indicate a material change in future operating results or financial condition.

Recently issued Statement of Financial Accounting Standards

Share-based payments

In December 2004, the Financial Accounting Standards Board (FASB) issued a revised Statement of Financial Accounting Standards No. 123 (SFAS 123R), Share-based Payments. SFAS 123R requires compensation costs related to share-based payment arrangements to employees to be recognized in the income statement over the requisite service period. The amount of the compensation cost will be measured based on the grant-date fair value of the instruments issued. In addition, liability awards will be remeasured each reporting period through settlement. SFAS 123R is effective for the company as of January 1, 2006, for all awards granted or modified after that date and for those awards granted prior to that date that have not vested. SFAS 123R will not have a material impact on the company's earnings because in 2003, the company adopted a policy of expensing all share-based payments that is consistent with the provisions of SFAS 123R and all prior year outstanding stock option awards have vested.

The cumulative compensation expense associated with stock-related awards made in 2002, 2003 and 2004 has been recognized in the consolidated income statement using the "nominal vesting period approach". The full cost of awards given to employees who have retired before the end of the vesting period has been expensed. The use of a "non-substantive vesting period approach" based on the retirement eligibility age would not be significantly different from the nominal vesting period approach. The non-substantive vesting period approach will be applicable to grants made after the adoption of SFAS 123R on January 1, 2006.

Accounting for purchases and sales of inventory with the same counterparty

At its September 2005 meeting, the Emerging Issues Task Force (EITF) reached a consensus on Issue No. 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty. This issue addresses the question of when it is appropriate to measure purchases and sales of inventory at fair value and record them in cost of sales and revenues 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.

The company currently records certain crude oil, natural gas, petroleum product and chemical purchases and sales of inventory entered into contemporaneously with the same counterparty as cost of sales and revenues, measured at fair value as agreed upon by a willing buyer and a willing seller. These transactions occur under contractual arrangements that establish the agreement terms either jointly, in a single contract, or separately, in individual contracts. This accounting treatment is consistent with long-standing industry practice (although the company understands that some companies in the oil and gas industry may be accounting for these transactions as nonmonetary exchanges). The EITF consensus will result in the company's accounts "operating revenues" and "purchases of crude oil and products" on the consolidated statement of income being reduced by associated amounts with no impact on net income. All operating segments will be impacted by this change, but the largest effects are in the petroleum products segment. The EITF consensus will become effective for new arrangements entered into, and modifications or renewals of existing agreements, beginning no later than the second quarter of 2006.

The purchase/sale amounts included in revenue for 2005, 2004 and 2003 are shown in note 1 to the consolidated financial statements on page 42.

Critical accounting policies

The company's financial statements have been prepared in accordance with United States generally accepted accounting principles (GAAP) and include estimates that reflect management's best judgment. The company's accounting and financial reporting fairly reflect its straightforward business model. Imperial does not use financing structures for the purpose of altering accounting outcomes or removing debt from the balance sheet. The following summary provides further information about the critical accounting policies and the estimates that are made by the company to apply those policies. It should be read in conjunction with note 1 to the consolidated financial statements on page 42.

Hydrocarbon reserves

Proved oil, gas and synthetic crude oil reserve quantities are used as the basis of calculating unit-of-production rates for depreciation and evaluating for impairment. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs and deposits under existing economic and operating conditions. Estimates of synthetic crude oil reserves are based on detailed geological and engineering assessments of in-place crude bitumen volume, the mining plan, historical extraction recovery and upgrading yield factors, installed plant operating capacity and operating approval limits.

The estimation of proved reserves is controlled by the company through long-standing approval guidelines. Reserve changes are made with a well-established, disciplined process driven by senior-level geoscience and engineering professionals (assisted by a central reserves group with significant technical experience), culminating in reviews with and approval by senior management and the company's board of directors. Key features of the estimation include rigorous peer-reviewed technical evaluations and analysis of well and field performance information and a requirement that management make a commitment toward the development of the reserves prior to booking. Notably, no employee is compensated based on the levels of proved reserves bookings.

Although the company is reasonably certain that proved reserves will be produced, the timing and ultimate recovery can be affected by a number of factors, including completion of development projects, reservoir performance and significant changes in long-term oil and gas price levels.

Based on the United States Securities and Exchange Commission regulatory guidance, the company has reported 2004 and 2005 reserves on the basis of December 31 prices and costs ("year-end prices").

The use of year-end prices for reserves estimation introduces short-term price volatility into the process since annual adjustments are required based on prices occurring on a single day. The company believes that this approach is inconsistent with the long-term nature of the natural resources business where production from individual projects often spans multiple decades. The use of prices from a single date is not relevant to the investment decisions made by the company, and annual variations in reserves based on such year-end prices are not of consequence to how the business is actually managed.

The impact of year-end prices on reserves estimation is most clearly shown at Cold Lake, where proved bitumen and associated natural gas reserves were reduced by about 137 million oil-equivalent barrels as a result of using December 31, 2005 prices, which were seasonally low. Prices of Cold Lake bitumen were strong for most of 2005, however, they began to deteriorate in the middle of the fourth quarter and ended on December 31, 2005 more than 25 percent below the year's average. Prices quickly rebounded from December 31, and through January 2006 returned to levels that have restored the reserves to the proved category, repeating the same reserves rebooking situation as in January 2005.

Revisions can include upward or downward changes in previously estimated volumes of proved reserves for existing fields due to the evaluation or revaluation of already available geologic, reservoir or production data; new geologic, reservoir or production data; or changes to underlying price assumptions used in the determination of reserves. This category can also include changes associated with the performance of improved recovery projects and significant changes in either development strategy or production equipment/facility capacity.

The company uses the successful-efforts method to account for its exploration and production activities. Under this method, costs are accumulated on a field-by-field basis with certain exploratory expenditures and exploratory dry holes being expensed as incurred. Costs of productive wells and development dry holes are capitalized and amortized on the unit-of-production method for each field. The company uses this accounting policy instead of the full-cost method because it provides a more timely accounting of the success or failure of the company's exploration and production activities.

Impact of reserves on depreciation
The calculation of unit-of-production depreciation is a critical accounting estimate that measures the depreciation of natural resources assets. It is the ratio of actual volumes produced to total proved developed reserves (those reserves recoverable through existing wells with existing equipment and operating methods) applied to the asset cost. The volumes produced and asset cost are known and, while proved developed reserves have a high probability of recoverability, they are based on estimates that are subject to some variability. This variability has generally resulted in net upward revisions of proved reserves in existing fields, as more information becomes available through research and production. Revisions have averaged eight million oil-equivalent barrels per year over the last five years and have resulted from effective reservoir management and the application of new technology. While the upward revisions the company has made over the last five years are an indicator of variability, they have had little impact on the unit-of-production rates of depreciation because they have been small compared to the large proved reserves base.

Impact of reserves and prices on testing for impairment
Proved oil and gas properties held and used by the company are reviewed for impairment whenever events or circumstances indicate that the carrying amounts may not be recoverable. Assets are grouped at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets.

The company estimates the future undiscounted cash flows of the affected properties to judge the recoverability of carrying amounts. In general, impairment analyses are based on proved reserves. Where probable reserves exist, an appropriately risk-adjusted amount of these reserves may be included in the impairment evaluation. An asset would be impaired if the undiscounted cash flows were less than its carrying value. Impairments are measured by the amount by which the asset's carrying value exceeds its fair value.

The impairment evaluation triggers include a significant decrease in current and projected prices or reserve volumes, an accumulation of project costs significantly in excess of the amount originally expected and historical and current operating losses.

In general, the company does not view temporarily low oil prices as a triggering event for conducting impairment tests. The markets for crude oil and natural gas have a history of significant price volatility. Although prices will occasionally drop precipitously, the relative growth/decline in supply versus demand will determine industry prices over the long term and these cannot be accurately predicted. Accordingly, any impairment tests that the company performs make use of the company's long-term price assumptions for crude oil and natural gas markets, petroleum products and chemicals. These are the same price assumptions that are used in the company's annual planning and budgeting processes and are also used for capital investment decisions. Any impairment tests that the company performs also make use of annual volumes based on individual field production profiles, which are also updated as part of the annual plan process.

The standardized measure of discounted future cash flows on page 64 is based on the year-end 2005 price applied for all future years, as required under Statement of Financial Accounting Standards No. 69 (SFAS 69). Future prices used for any impairment tests will vary from the one used in the SFAS 69 disclosure and could be lower or higher for any given year.

Retirement benefits
The company's pension plan is managed in compliance with the requirements of governmental authorities and meets funding levels as determined by independent third-party actuaries. Pension accounting requires explicit assumptions regarding, among others, the discount rate for the benefit obligations, the expected rate of return on plan assets and the long-term rate of future compensation increases. All pension assumptions are reviewed annually by senior management. These assumptions are adjusted only as appropriate to reflect long-term changes in market rates and outlook. The long-term expected rate of return on plan assets of 8.25 percent used in 2005 compares to actual returns of 10 percent and 9.64 percent achieved over the last 10- and 20-year periods ending December 31, 2005. If different assumptions are used, the expense and obligations could increase or decrease as a result. The company's potential exposure to changes in assumptions is summarized in note 6 to the consolidated financial statements on page 49. At Imperial, differences between actual returns on plan assets versus long-term expected returns are not recorded in the year the differences occur, but rather are amortized in pension expense as permitted by GAAP, along with other actuarial gains and losses, over the expected remaining service life of employees. The company uses the fair value of the plan assets at year-end to determine the amount of the actual gain or loss that will be amortized and does not use a moving average value of plan assets. Pension expense represented less than one percent of total expenses in 2005.

Asset retirement obligations and other environmental liabilities
Legal obligations associated with site restoration on the retirement of assets with determinable useful lives are recognized when they are incurred, which is typically at the time the assets are installed. The obligations are initially measured at fair value and discounted to present value. Over time, the discounted asset retirement obligation amount will be accreted for the change in its present value, with this effect included in operating expense. As payments to settle the obligations occur on an ongoing basis and will continue over the lives of the operating assets, which can exceed 25 years, the discount rate will be adjusted only as appropriate to reflect long-term changes in market rates and outlook. For 2005, the obligations were discounted at six percent and the accretion expense was $20 million, before tax, which was significantly less than one percent of total expenses in the year. There would be no material impact on the company's reported financial results if a different discount rate had been used.

Asset retirement obligations are not recognized for assets with an indeterminate useful life. For these and non-operating assets, the company accrues provisions for environmental liabilities when it is probable that obligations have been incurred and the amount can be reasonably estimated.

Asset retirement obligations and other environmental liabilities are based on engineering estimated costs, taking into account the anticipated method and extent of remediation consistent with legal requirements, current technology and the possible use of the location. Since these estimates are specific to the locations involved, there are many individual assumptions underlying the company's total asset retirement obligations and provision for other environmental liabilities. While these individual assumptions can be subject to change, none of them is individually significant to the company's reported financial results.

Market risks and other uncertainties

The company is exposed to a variety of financial, operating and market risks in the course of its business. Some of these risks are within the company's control, while others are not. For those risks that can be controlled, specific risk-management strategies are employed to reduce the likelihood of loss.

Although the government of Canada, in ratifying the Kyoto Protocol, agreed to restrictions of greenhouse-gas emissions by the period 2008–2012, it has not determined what measures it will impose on companies. Consequently, attempts to assess the impact on Imperial can only be speculative. The company will continue to monitor the development of legal requirements in this area.

Other risks, such as changes in international commodity prices and currency-exchange rates, are beyond the company's control. The company's size, strong financial position and the complementary nature of its natural resources, petroleum products and chemicals segments help mitigate the company's exposure to changes in these other risks. The company's potential exposure to these types of risk is summarized in the earnings sensitivity table below.

The company does not use derivative markets to speculate on the future direction of currency or commodity prices and does not sell forward any part of production from any business segment.

The following table shows the estimated annual effect, under current conditions, of certain sensitivities of the company's after-tax net income.

Earnings sensitivities (a)

millions of dollars after tax

Six dollars (U.S.) a barrel change in crude oil prices	+ (-)	$ 300
One dollar and ten cents a thousand cubic feet change in natural gas prices	+ (-)	$ 66
One cent a litre change in sales margins for total petroleum products	+ (-)	$ 175
One cent (U.S.) a pound change in sales margins for polyethylene	+ (-)	$ 7
One-quarter percent decrease (increase) in short-term interest rates	+ (-)	$ 2
Nine cents decrease (increase) in the value of the Canadian dollar versus the U.S. dollar	+ (-)	$ 475

(a) The amount quoted to illustrate the impact of each sensitivity represents a change of about 10 percent in the value of the commodity or rate in question at the end of 2005. Each sensitivity calculation shows the impact on net income that results from a change in one factor, after tax and royalties and holding all other factors constant. While these sensitivities are applicable under current conditions, they may not apply proportionately to larger fluctuations.

The sensitivity of net income to changes in the Canadian dollar versus the U.S. dollar increased from year-end 2004 by about $20 million (after tax) a year for each one-cent change. This is primarily due to the increase in crude oil prices and industry refining margins.

Frequently used financial terms

Listed below are definitions of four of Imperial's frequently used financial performance measures. The definitions are provided to facilitate understanding of the terms and how they are calculated.

Capital employed

Capital employed is a measure of net investment. When viewed from the perspective of how capital is used by the business, it includes the company's property, plant and equipment and other assets, less liabilities, excluding both short-term and long-term debt. When viewed from the perspective of the sources of capital employed for the whole company, it includes total debt and shareholders' equity. Both of these views include the company's share of amounts applicable to equity companies.

millions of dollars	2005	2004	2003
Business uses: asset and liability perspective			
Total assets	**15 582**	14 027	12 337
Less: total current liabilities excluding short-term debt and current portion of long-term debt	**(4 569)**	(3 582)	(2 817)
Less: total long-term liabilities excluding long-term debt	**(2 941)**	(2 680)	(2 543)
Add: Imperial's share of equity company debt	**59**	56	52
Total capital employed	**8 131**	7 821	7 029

millions of dollars	2005	2004	2003
Total company sources: debt and equity perspective			
Short-term debt and current portion of long-term debt	**576**	1 076	573
Long-term debt	**863**	367	859
Shareholders' equity	**6 633**	6 322	5 545
Add: Imperial's share of equity company debt	**59**	56	52
Total capital employed	**8 131**	7 821	7 029

Return on average capital employed (ROCE)

ROCE is a financial performance ratio. For each of the company's business segments, ROCE is annual business-segment net income divided by average business-segment capital employed (an average of the beginning and end-of-year amounts). Segment net income includes Imperial's share of segment net income of equity companies, consistent with the definition used for capital employed, and excludes the cost of financing. The company's total ROCE is net income excluding the after-tax cost of financing divided by total average capital employed. The company has consistently applied its ROCE definition for many years and views it as the best measure of historical capital productivity in a capital-intensive, long-term industry to both evaluate management's performance and demonstrate to shareholders that capital has been used wisely over the long term.

millions of dollars	2005	2004	2003
Net income	**2 600**	2 052	1 705
Financing costs (after tax), including Imperial's share of equity companies	**3**	3	3
Net income excluding financing costs	**2 603**	2 055	1 708
Average capital employed	**7 976**	7 425	6 764
Return on average capital employed (percent)	**32.6**	27.7	25.3

Operating costs

Operating costs are the combined total of production, manufacturing, selling, general, exploration, depreciation and depletion expenses from the consolidated statement of income and Imperial's share of similar costs for equity companies. Operating costs are the costs incurred during the period to produce, manufacture and otherwise prepare the company's products for sale – including energy costs, staffing, maintenance and other costs to explore for and produce oil and gas and operate refining and chemical plants. Delivery costs to customers and marketing expenses are also included. Operating costs exclude the cost of raw materials and those costs incurred in bringing inventory to its existing condition and final storage prior to delivery to a customer. These expenses are on a before-tax basis. While Imperial's management is responsible for all revenue and expense elements of net income, operating costs, as defined below, represent the expenses most directly under management's control.

millions of dollars	2005	2004	2003
Expenses (from page 38)			
Exploration	**43**	59	55
Production and manufacturing	**3 327**	2 820	2 726
Selling and general	**1 577**	1 281	1 325
Depreciation and depletion	**895**	908	755
Subtotal	**5 842**	5 068	4 861
Imperial's share of equity company expenses	**56**	52	56
Total operating costs	**5 898**	5 120	4 917

Cash flow from operating activities and asset sales

Cash flow from operating activities and asset sales is the sum of the net cash provided by operating activities and proceeds from asset sales reported in the consolidated statement of cash flows. This cash flow is the total source of cash both from operating the company's assets and from the divesting of assets. The company employs a long-standing, disciplined regular review process to ensure that all assets are contributing to the company's strategic and financial objectives. Assets are divested when they no longer meet these objectives or are worth considerably more to others. Because of the regular nature of this activity, management believes it is useful for investors to consider sales proceeds together with cash provided by operating activities when evaluating cash available for investment in the business and financing activities, including shareholder distributions.

millions of dollars	**2005**	2004	2003
Cash from operating activities	**3 451**	3 312	2 227
Proceeds from asset sales	**440**	102	56
Total cash flow from operating activities and asset sales	**3 891**	3 414	2 283

Supplemental information based on generally accepted accounting principles (GAAP) in Canada

The company's financial summary and management's discussion and analysis, under Canadian GAAP, are not materially different from those reported under U.S. GAAP as shown on pages 20 to 34, except for the following:

Financial summary

millions of dollars	**2005**	2004	2003	2002	2001
Net income by segment:					
Natural resources	**2 008**	1 517	1 170	1 066	969
Petroleum products	**694**	556	462	147	376
Chemicals	**121**	109	44	54	26
Corporate and other	**(246)**	(149)	6	(43)	(116)
Net income	**2 577**	2 033	1 682	1 224	1 255
Total assets	**15 738**	13 992	12 361	11 894	10 781
Other long-term obligations	**1 125**	1 010	972	1 207	1 098
Capital employed	**8 636**	8 137	7 262	6 803	5 841
Cash flow from operating activities and asset sales	**3 850**	3 380	2 250	1 737	2 050
Per-share information (dollars)					
Net income per share -- basic	**7.55**	5.70	4.52	3.23	3.19
Net income per share -- diluted	**7.52**	5.69	4.52	3.23	3.19

Results of operations

Net income in 2005 was $2,577 million or $7.52 a share – the best year on record – compared with the then record of $2,033 million or $5.69 a share in 2004 (2003 – $1,682 million or $4.52 a share). Strong operational performance in 2005 allowed the company to capture opportunities in an environment of higher commodity prices and industry margins. Higher realizations for crude oil, natural gas and Cold Lake bitumen and stronger refining margins contributed about $1,300 million to earnings when compared to 2004. Also positive to earnings was increased natural gas and Cold Lake bitumen volumes of about $125 million. These factors were partly offset by a stronger Canadian dollar, lower volumes at Syncrude, the natural decline of conventional crude oil volumes and higher planned maintenance impacting refinery operations. These factors had a combined negative impact of about $590 million on earnings. Operating costs increased and impacted earnings by about $325 million, primarily driven by higher energy costs and higher Syncrude maintenance expenses. In addition, stock-related compensation expenses were $143 million higher than a year earlier and costs associated with the head office relocation of about $45 million were incurred in 2005. Included in net income in 2005 was a $233 million gain on sale of assets, mainly from the Redwater and North Pembina fields. Included in net income in 2004 was a $32 million gain on sale of assets and a write down of $42 million on a north Toronto property.

The return on average capital employed was 31 percent, compared with 26 percent in 2004 (2003 – 24 percent).

Natural resources

Net income from natural resources was $2,008 million, up from $1,517 million in 2004 (2003 – $1,170 million). Improved realizations for crude oil, natural gas and Cold Lake bitumen of about $910 million and higher natural gas and Cold Lake bitumen volumes of about $125 million were the main reasons for the increase. Their positive impact on earnings was partially offset by the unfavourable impact of a higher Canadian dollar of about $260 million, lower volumes due to higher maintenance activities at Syncrude of about $100 million and the natural decline of conventional crude oil and NGL volumes of about $90 million. Operating costs were also higher than 2004 by about $275 million, primarily driven by higher energy costs of about $140 million and higher Syncrude maintenance and other expenses of about $75 million. Included in net income in 2005 was a $208 million gain on sale of assets, mainly from the Redwater and North Pembina fields. Included in net income in 2004 was a $25 million gain on sale of assets.

Return on average capital employed was 51 percent for the natural resources segment, compared with 39 percent in 2004 (2003 – 33 percent), reflecting higher net income.

Financial statistics

millions of dollars	**2005**	2004	2003	2002	2001
Net income	**2 008**	1 517	1 170	1 066	969
Capital employed at December 31	**3 906**	3 951	3 803	3 338	2 593
Return on average capital employed (percent)	**51.1**	39.1	32.8	35.9	40.8

Petroleum products

Return on average capital employed was 24 percent for the petroleum products segment, compared with 20 percent in 2004 (2003 – 17 percent).

Financial statistics

millions of dollars	**2005**	2004	2003	2002	2001
Capital employed at December 31	**3 036**	2 774	2 890	2 552	2 217
Return on average capital employed (percent)	**23.9**	19.6	17.0	6.2	16.5

Chemicals

Return on average capital employed was 45 percent for the chemicals segment, compared with 42 percent in 2004 (2003 – 20 percent).

Financial statistics

millions of dollars	**2005**	2004	2003	2002	2001
Capital employed at December 31	**281**	262	257	188	203
Return on average capital employed (percent)	**44.6**	42.0	19.8	27.6	14.9

Corporate and other

Net income from corporate and other accounts was negative $246 million in 2005, compared with negative $149 million in 2004 (2003 – positive $6 million). Lower net income in 2005 was mainly due to higher stock-related compensation expenses of about $143 million largely driven by the increase in the company's share price from a year earlier, partially offset by the absence of a write down of $42 million on a north Toronto property previously recorded in 2004.

Capital and exploration expenditures

Total capital and exploration expenditures were $1,434 million in 2005, up from $1,411 million in 2004 (2003 – $1,526 million).

Management's report on internal control over financial reporting

Management, including the company's chief executive officer and principal accounting officer and principal financial officer, is responsible for establishing and maintaining adequate internal control over the company's financial reporting. Management conducted an evaluation of the effectiveness of internal control over financial reporting based on the *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Imperial Oil Limited's internal control over financial reporting was effective as of December 31, 2005.

Management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2005, was audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

T.J. Hearn
Chairman, president and chief executive officer

P.A. Smith
Controller and senior vice-president,
finance and administration
(Principal accounting officer and principal financial officer)

February 27, 2006

Auditors' report

To the Shareholders of Imperial Oil Limited
We have completed an integrated audit of Imperial Oil Limited's 2005 and 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2005 and an audit of its 2003 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions on Imperial Oil Limited's 2005, 2004 and 2003 consolidated financial statements and on its internal control over financial reporting at December 31, 2005, based on our audits, are presented below.

Consolidated financial statements
In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, shareholders' equity and cash flows appearing on pages 38 through 62 of this Annual Report present fairly, in all material respects, the financial position of Imperial Oil Limited and its subsidiaries at December 31, 2005 and 2004, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2005 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statements presentation. We believe that our audits provide a reasonable basis for our opinion.

Internal control over financial reporting
Also, in our opinion, management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that the company maintained effective internal control over financial reporting as of December 31, 2005 based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control – Integrated Framework* issued by the COSO. The company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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

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

PricewaterhouseCoopers LLP.

Chartered Accountants
Toronto, Ontario
February 27, 2006

Consolidated statement of income (U.S. GAAP)

millions of Canadian dollars For the years ended December 31	2005	2004	2003
Revenues and other income			
Operating revenues (a) (b)	**27 797**	22 408	19 094
Investment and other income (note 10)	**417**	52	114
Total revenues and other income	**28 214**	22 460	19 208
Expenses			
Exploration	**43**	59	55
Purchases of crude oil and products (b)	**17 168**	13 094	10 823
Production and manufacturing	**3 327**	2 820	2 726
Selling and general	**1 577**	1 281	1 325
Federal excise tax (a)	**1 278**	1 264	1 254
Depreciation and depletion	**895**	908	755
Financing costs (note 14)	**8**	7	(120)
Total expenses	**24 296**	19 433	16 818
Income before income taxes	**3 918**	3 027	2 390
Income taxes (note 4)	**1 318**	975	689
Income before cumulative effect of accounting change	**2 600**	2 052	1 701
Cumulative effect of accounting change, after income tax	**–**	–	4
Net income	**2 600**	2 052	1 705
Per-share information (Canadian dollars)			
Net income per common share – basic (note 12)			
Income before cumulative effect of accounting change	**7.62**	5.75	4.57
Cumulative effect of accounting change, after income tax	**–**	–	0.01
Net income	**7.62**	5.75	4.58
Net income per common share – diluted (note 12)			
Income before cumulative effect of accounting change	**7.59**	5.74	4.57
Cumulative effect of accounting change, after income tax	**–**	–	0.01
Net income	**7.59**	5.74	4.58
Dividends	**0.94**	0.88	0.87

(a) Operating revenues include federal excise tax of $1,278 million (2004 – $1,264 million, 2003 – $1,254 million).

(b) Operating revenues include amounts for purchase / sale contracts with the same counterparty (associated costs are included in "purchases of crude oil and products") of $4,894 million (2004 – $3,584 million, 2003 – $2,851 million).

The information on pages 42 through 62 is part of these consolidated financial statements. Certain figures for prior years have been reclassified in the financial statements to conform with the current year's presentation.

Consolidated statement of cash flows (U.S. GAAP)

millions of Canadian dollars inflow/(outflow) For the years ended December 31	2005	2004	2003
Operating activities			
Net income	**2 600**	2 052	1 705
Cumulative effect of accounting change, after tax	**–**	–	(4)
Adjustments for non-cash items:			
Depreciation and depletion	**895**	908	755
(Gain)/loss on asset sales, after tax	**(233)**	(32)	(10)
Deferred income taxes and other	**(116)**	(90)	(59)
Changes in operating assets and liabilities:			
Accounts receivable	**(414)**	(311)	33
Inventories and prepaids	**(67)**	(32)	31
Income taxes payable	**304**	462	38
Accounts payable	**644**	308	74
All other items – net (a)	**(162)**	47	(336)
Cash from operating activities	**3 451**	3 312	2 227
Investing activities			
Additions to property, plant and equipment and intangibles	**(1 432)**	(1 376)	(1 482)
Proceeds from asset sales	**440**	102	56
Loans to equity company	**–**	(32)	–
Cash from (used in) investing activities	**(992)**	(1 306)	(1 426)
Financing activities			
Short-term debt – net	**18**	9	–
Long-term debt issued	**–**	–	818
Repayment of long-term debt	**(21)**	(8)	(818)
Issuance of common shares under stock option plan	**38**	13	2
Common shares purchased (note 12)	**(1 795)**	(872)	(799)
Dividends paid	**(317)**	(317)	(322)
Cash from (used in) financing activities	**(2 077)**	(1 175)	(1 119)
Increase (decrease) in cash	**382**	831	(318)
Cash at beginning of year	**1 279**	448	766
Cash at end of year (b)	**1 661**	1 279	448

(a) Includes contribution to registered pension plans of $350 million (2004 – $114 million, 2003 – $511 million).

(b) Cash is composed of cash in bank and cash equivalents at cost. Cash equivalents are all highly liquid securities with maturity of three months or less when purchased.

The information on pages 42 through 62 is part of these consolidated financial statements. Certain figures for prior years have been reclassified in the financial statements to conform with the current year's presentation.

Consolidated balance sheet (U.S. GAAP)

millions of Canadian dollars At December 31	2005	2004
Assets		
Current assets		
Cash	**1 661**	1 279
Accounts receivable, less estimated doubtful amounts	**2 040**	1 626
Inventories of crude oil and products (note 13)	**481**	432
Materials, supplies and prepaid expenses	**130**	112
Deferred income tax assets (note 4)	**654**	448
Total current assets	**4 966**	3 897
Investments and other long-term assets	**127**	130
Property, plant and equipment, less accumulated depreciation and depletion (note 2)	**10 132**	9 647
Goodwill (note 2)	**204**	204
Other intangible assets, net	**153**	149
Total assets (note 2)	**15 582**	14 027
Liabilities		
Current liabilities		
Short-term debt	**99**	81
Accounts payable and accrued liabilities (note 15)	**3 170**	2 525
Income taxes payable	**1 399**	1 057
Current portion of long-term debt	**477**	995
Total current liabilities	**5 145**	4 658
Long-term debt (note 3)	**863**	367
Other long-term obligations (note 7)	**1 728**	1 525
Deferred income tax liabilities (note 4)	**1 213**	1 155
Commitments and contingent liabilities (note 11)		
Total liabilities	**8 949**	7 705
Shareholders' equity		
Common shares at stated value (note 12)	**1 747**	1 801
Earnings reinvested	**5 466**	4 889
Accumulated other nonowner changes in equity	**(580)**	(368)
Total shareholders' equity	**6 633**	6 322
Total liabilities and shareholders' equity	**15 582**	14 027

The information on pages 42 through 62 is part of these consolidated financial statements. Certain figures for prior years have been reclassified in the financial statements to conform with the current year's presentation.

Approved by the directors

T.J. Hearn
Chairman, president and
chief executive officer

P.A. Smith
Controller and senior vice-president,
finance and administration

Consolidated statement of shareholders' equity (U.S. GAAP)

millions of Canadian dollars At December 31	**2005**	2004	2003
Common shares at stated value (note 12)			
At beginning of year	**1 801**	1 859	1 939
Issued under the stock option plan	**38**	13	2
Share purchases at stated value	**(92)**	(71)	(82)
At end of year	**1 747**	1 801	1 859
Earnings reinvested			
At beginning of year	**4 889**	3 952	3 287
Net income for the year	**2 600**	2 052	1 705
Share purchases in excess of stated value	**(1 703)**	(801)	(717)
Dividends	**(320)**	(314)	(323)
At end of year	**5 466**	4 889	3 952
Accumulated other nonowner changes in equity			
At beginning of year	**(368)**	(266)	(315)
Minimum pension liability adjustment (note 6)	**(212)**	(102)	49
At end of year	**(580)**	(368)	(266)
Shareholders' equity at end of year	**6 633**	6 322	5 545
Nonowner changes in equity for the year			
Net income for the year	**2 600**	2 052	1 705
Other nonowner changes in equity (note 6)	**(212)**	(102)	49
Total nonowner changes in equity for the year	**2 388**	1 950	1 754

The information on pages 42 through 62 is part of these consolidated financial statements. Certain figures for prior years have been reclassified in the financial statements to conform with the current year's presentation.

Notes to consolidated financial statements

1. Summary of significant accounting policies

The company's principal business is energy, involving the exploration, production, transportation and sale of crude oil and natural gas and the manufacture, transportation and sale of petroleum products. The company is also a major manufacturer and marketer of petrochemicals.

The consolidated financial statements have been prepared in accordance with generally accepted accounting principles (GAAP) in the United States of America. A description of the differences between GAAP in Canada and in the United States as they apply to the company, including a reconciliation of net income, cash flows and impacted balance sheet line items, is provided in note 17. The financial statements include certain estimates that reflect management's best judgment. All amounts are in Canadian dollars unless otherwise indicated.

Principles of consolidation

The consolidated financial statements include the accounts of Imperial Oil Limited and its subsidiaries. Intercompany accounts and transactions are eliminated. Subsidiaries include those companies in which Imperial has both an equity interest and the continuing ability to unilaterally determine strategic, operating, investing and financing policies. Significant subsidiaries included in the consolidated financial statements include Imperial Oil Resources Limited, Imperial Oil Resources N.W.T. Limited, Imperial Oil Resources Ventures Limited and McColl-Frontenac Petroleum Inc. All of the above companies are wholly owned. A significant portion of the company's activities in natural resources is conducted jointly with other companies. The accounts reflect the company's share of undivided interest in such activities, including its 25 percent interest in the Syncrude joint venture and its nine percent interest in the Sable offshore energy project.

Segment reporting

The company operates its business in Canada in the following segments:
Natural resources includes the exploration for and production of crude oil and natural gas.
Petroleum products comprises the refining of crude oil into petroleum products and the distribution and marketing of these products.
Chemicals includes the manufacturing and marketing of various hydrocarbon-based chemicals and chemical products.

The above functions have been defined as the operating segments of the company because they are the segments (a) that engage in business activities from which revenues are earned and expenses are incurred; (b) whose operating results are regularly reviewed by the company's chief operating decision maker to make decisions about resources to be allocated to each segment and assess its performance; and (c) for which discrete financial information is available.

Corporate and other includes assets and liabilities that do not specifically relate to business segments – primarily cash, long-term debt and liabilities associated with incentive compensation. Net income in this segment primarily includes financing costs, interest income and incentive compensation expenses.

Segment accounting policies are the same as those described in this summary of significant accounting policies. Natural resources, petroleum products and chemicals expenses include amounts allocated from the "corporate and other" segment. The allocation is based on a combination of fee for service, proportional segment expenses and a three-year average of capital expenditures. Transfers of assets between segments are recorded at book amounts. Items included in capital employed that are not identifiable by segment are allocated according to their nature.

Inventories

Inventories are recorded at the lower of cost or net realizable value. The cost of crude oil and products is determined primarily using the last-in, first-out (LIFO) method. LIFO was selected over the alternative first-in, first-out and average cost methods because it provides a better matching of current costs with the revenues generated in the period.

Inventory costs include expenditures and other charges, including depreciation, directly or indirectly incurred in bringing the inventory to its existing condition and final storage prior to delivery to a customer. Selling and general expenses are reported as period costs and excluded from inventory costs.

Investments

The principal investments in companies other than subsidiaries are accounted for using the equity method. They are recorded at the original cost of the investment plus Imperial's share of earnings since the investment was made, less dividends received. Imperial's share of the after-tax earnings of these companies is included in "investment and other income" in the consolidated statement of income. Other investments are recorded at cost. Dividends from these other investments are included in "investment and other income."

These investments represent interests in non-publicly traded pipeline companies that facilitate the sale and purchase of crude oil and natural gas in the conduct of company operations. Other parties who also have an equity interest in these companies share in the risks and rewards according to their percentage of ownership. Imperial does not invest in these companies in order to remove liabilities from its balance sheet.

Property, plant and equipment

Property, plant and equipment are recorded at cost. Investment tax credits and other similar grants are treated as a reduction of the capitalized cost of the asset to which they apply.

The company uses the successful-efforts method to account for its exploration and development activities. Under this method, costs are accumulated on a field-by-field basis with certain exploratory expenditures and exploratory dry holes being expensed as incurred. Effective July 1, 2005, the company adopted Financial Accounting Standards Board Staff Position FAS 19-1 (FSP 19-1), Accounting for Suspended Well Costs. FSP 19-1 amended Statement of Financial Accounting Standards No. 19 (SFAS 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 adoption of FSP 19-1. Prior to the adoption of FSP 19-1, the company carried as an asset the cost of drilling exploratory wells that found sufficient quantities of reserves to justify their completion as producing wells if the required capital expenditure was made and drilling of additional exploratory wells was underway or firmly planned for the near future. Once exploration activities demonstrated that sufficient quantities of commercially producible reserves had been discovered, continued capitalization was dependent on project reviews, which took place at least annually, to ensure that satisfactory progress toward ultimate development of the reserves was being achieved. Exploratory well costs not meeting these criteria were charged to expense. Capitalized exploratory drilling costs pending the determination of proved reserves or the amount of suspended exploratory well costs were $13 million, negligible and $2 million at December 31, 2005, 2004 and 2003, respectively. Costs of productive wells and development dry holes are capitalized and amortized on the unit-of-production method for each field. The company uses this accounting policy instead of the full-cost method because it provides a more timely accounting of the success or failure of the company's exploration and production activities.

Maintenance and repair costs, including planned major maintenance, are expensed as incurred. Improvements that increase or prolong the service life or capacity of an asset are capitalized.

Production costs are expensed as incurred. Production involves lifting the oil and gas to the surface and gathering, treating, field processing and field storage of the oil and gas. The production function normally terminates at the outlet valve on the lease or field production storage tank. Production costs are those incurred to operate and maintain the company's wells and related equipment and facilities. They become part of the cost of oil and gas produced. These costs, sometimes referred to as lifting costs, include such items as labour cost to operate the wells and related equipment; repair and maintenance costs on the wells and equipment; materials, supplies and energy costs required to operate the wells and related equipment; and administrative expenses related to the production activity.

Depreciation and depletion for assets associated with producing properties begin at the time when production commences on a regular basis. Depreciation for other assets begins when the asset is in place and ready for its intended use. Assets under construction are not depreciated or depleted. Depreciation and depletion are calculated using the unit-of-production method for producing properties based on proved developed reserves. Depreciation of other plant and equipment is calculated using the straight-line method, based on the estimated service life of the asset. In general, refineries are depreciated over 25 years; other major assets, including chemical plants and service stations, are depreciated over 20 years.

Proved oil and gas properties held and used by the company are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recoverable. Assets are grouped at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets.

The company estimates the future undiscounted cash flows of the affected properties to judge the recoverability of carrying amounts. Cash flows used in impairment evaluations are developed using annually updated corporate plan investment evaluation assumptions for crude oil commodity prices and foreign-currency exchange rates. Annual volumes are based on individual field production profiles, which are also updated annually. Prices for natural gas and other products sold under contract are based on corporate plan assumptions developed annually by major contracts and also for investment evaluation purposes.

In general, impairment analyses are based on proved reserves. Where probable reserves exist, an appropriately risk-adjusted amount of these reserves may be included in the impairment evaluation. An asset would be impaired if the undiscounted cash flows were less than its carrying value. Impairments are measured by the amount by which the carrying value exceeds its fair value.

Accounting policies for the company's tar sands operation are the same as those described in this summary of significant accounting policies for the company's crude oil and natural gas operations. The capitalization policy for the company's tar sands operation is that acquisition costs are capitalized when incurred. Exploration costs are expensed as incurred. The capitalization of development costs begins only after a determination of proven reserves has been made. With a consistently low level of inventory, the company expenses stripping costs during the production phase on an as incurred basis. The company's share of inventory at the company's tar sands operation was $20 million, $13 million and $14 million at December 31, 2005, 2004 and 2003 respectively. Recognizing stripping costs during the production phase as inventory costs would not have a significant impact on earnings or inventory value.

Amortization for tar sands assets begins at the time when production commences on a regular basis. Assets under construction are not amortized. Amortization of tar sands assets is a combination of unit-of-production and straight-line methods. Investments in the extraction facilities, which separate crude bitumen from sand, as well as the upgrading facilities, are amortized on a unit-of-production method based on proven developed reserves currently within an area of interest. Investments in the mining and transportation systems are amortized on a straight-line basis. In general, these assets are amortized over 15 years.

Gains or losses on assets sold are included in “investment and other income” in the consolidated statement of income.

Interest capitalization

Interest costs relating to major capital projects under construction are capitalized as part of property, plant, and equipment. Capitalization of interest ceases when the related asset is substantially complete and ready for its intended use.

Goodwill and other intangible assets

Goodwill is not subject to amortization. Goodwill is tested for impairment annually or more frequently if events or circumstances indicate it might be impaired. Impairment losses are recognized in current period earnings. The evaluation for impairment of goodwill is based on a comparison of the carrying values of goodwill and associated operating assets with the estimated present value of net cash flows from those operating assets.

Intangible assets with determinable useful lives are amortized over the estimated service lives of the assets. Computer software development costs are amortized over a maximum of 15 years and customer lists are amortized over a maximum of 10 years. The amortization is included in “depreciation and depletion” in the consolidated statement of income.

Asset retirement obligations and other environmental liabilities

Legal obligations associated with site restoration on the retirement of assets with determinable useful lives are recognized when they are incurred, which is typically at the time the assets are installed. These obligations primarily relate to decommissioning and removal costs of oil and gas wells and related facilities. The obligations are initially measured at fair value and discounted to present value. A corresponding amount equal to that of the initial obligation is added to the capitalized costs of the related asset. Over time the discounted asset retirement obligation amount will be accreted for the change in its present value, and the initial capitalized costs will be depreciated over the useful lives of the related assets.

No asset retirement obligations are set up for those manufacturing, distribution and marketing facilities with an indeterminate useful life, because such potential obligations cannot be measured since it is not possible to estimate the settlement dates. These are primarily currently operated sites. Provision for environmental liabilities of these and non-operating assets is made when it is probable that obligations have been incurred and the amount can be reasonably estimated. These liabilities are not discounted. Asset retirement obligations and other provisions for environmental liabilities are determined based on engineering estimated costs, taking into account the anticipated method and extent of remediation consistent with legal requirements, current technology and the possible use of the location.

Foreign-currency translation

Monetary assets and liabilities in foreign currencies have been translated at the rates of exchange prevailing on December 31. Any exchange gains or losses are recognized in income.

Financial instruments

The fair values of cash, accounts receivable and current liabilities approximate recorded amounts because of the short period to receipt or payment of cash. The fair value of the company’s long-term debt is estimated based on quoted market prices for the same or similar issues or on the current rates offered to the company for debt of the same duration to maturity. The fair values of the company’s other financial instruments, which are mainly long-term receivables, are estimated primarily by discounting future cash flows, using current rates for similar financial instruments under similar credit risk and maturity conditions.

The company does not use financing structures for the purpose of altering accounting outcomes or removing debt from the balance sheet. The company does not use derivative instruments to speculate on the future direction of currency or commodity prices and does not sell forward any part of production from any business segment.

Revenues

Revenues associated with sales of crude oil, natural gas, petroleum and chemical products and other items are recorded when the products are delivered. Delivery occurs when the customer has taken title and has assumed the risks and rewards of ownership, prices are fixed or determinable and collectibility is reasonably assured. The company does not enter into ongoing arrangements whereby it is required to repurchase its products, nor does the company provide the customer with a right of return.

Revenues include amounts billed to customers for shipping and handling. Shipping and handling costs incurred up to the point of final storage prior to delivery to a customer are included in “purchases of crude oil and products” in the consolidated statement of income. Delivery costs from final storage to customer are recorded as a marketing expense in “selling and general” expenses.

At its September 2005 meeting, the Emerging Issues Task Force (EITF) reached a consensus on Issue No. 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty. This issue addresses the question of when it is appropriate to measure purchases and sales of inventory at fair value and record them in cost of sales and revenues 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.

The company currently records certain crude oil, natural gas, petroleum product and chemical purchases and sales of inventory entered into contemporaneously with the same counterparty as cost of sales and revenues, measured at fair value as agreed upon by a willing buyer and a willing seller. These transactions occur under contractual arrangements that establish the agreement terms either jointly, in a single contract, or separately in individual contracts. The accounting treatment is consistent with long standing industry practice (although the company understands that some companies in the oil and gas industry may be accounting for these transactions as nonmonetary exchanges). The EITF consensus will result in the company's accounts "operating revenues" and "purchases of crude oil and products" on the consolidated statement of income being reduced by associated amounts with no impact on net income. All operating segments will be impacted by this change, but the largest effects are in the petroleum products segment. The EITF consensus will become effective for new arrangements entered into, and modifications or renewals of existing agreements, beginning no later than the second quarter of 2006.

The purchase/sale amounts included in revenue for 2005, 2004 and 2003 are shown below along with total "operating revenues" to provide context.

millions of dollars	**2005**	2004	2003
Operating revenues	**27 797**	22 408	19 094
Amounts included in operating revenues for purchase/ sale contracts with the same counterparty (a)	**4 894**	3 584	2 851
Percent of operating revenues	**18%**	16%	15%

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

Stock-based compensation

The company accounts for its stock-based compensation programs, except for the incentive stock options granted in April 2002, by using the fair-value-based method. Under this method, compensation expense related to the units of these programs is measured each reporting period based on the company's current share price and is recorded in the consolidated statement of income over the vesting period.

Compensation expense associated with stock-related awards has been recognized in the consolidated statement of income using the "nominal vesting period approach". The full cost of awards given to employees who have retired before the end of the vesting period has been expensed. The use of a "non-substantive vesting period approach" reflecting amortization based on the retirement eligibility age would not be significantly different from the nominal vesting period approach.

As permitted by Statement of Accounting Standard (SFAS) No. 123, the company continues to apply the intrinsic-value-based method of accounting for the incentive stock options granted in April 2002. Under this method, compensation expense is not recognized on the issuance of stock options as the exercise price is equal to the market value at the date of grant. All incentive stock options have vested as of January 1, 2005.

If the provisions of SFAS No. 123 had been adopted for all prior years, net income and net income per share would have been as below:

millions of dollars	**2005**	2004	2003
Net income as shown in financial statements	**2 600**	2 052	1 705
Add: stock-based compensation expense as reported, net of tax	**238**	95	93
Deduct: stock-based compensation expense, net of tax, determined under fair-value-based method	**(238)**	(97)	(98)
Pro forma net income	**2 600**	2 050	1 700
Net income per share (dollars)			
As reported – basic	**7.62**	5.75	4.58
– diluted	**7.59**	5.74	4.58
Pro forma – basic	**7.62**	5.75	4.57
– diluted	**7.59**	5.73	4.57

Consumer taxes

Taxes levied on the consumer and collected by the company are excluded from the consolidated statement of income. These are primarily provincial taxes on motor fuels and the federal goods and services tax.

2. Business segments

	Natural resources (a)			Petroleum products			Chemicals		
millions of dollars	**2005**	2004	2003	**2005**	2004	2003	**2005**	2004	2003
Revenues and other income									
External sales (b)	**4 702**	3 689	3 390	**21 793**	17 503	14 710	**1 302**	1 216	994
Intersegment sales (c)	**3 487**	2 891	2 224	**2 224**	1 666	1 294	**363**	293	238
Investment and other income	**331**	45	34	**60**	42	54	**–**	–	–
	8 520	6 625	5 648	**24 077**	19 211	16 058	**1 665**	1 509	1 232
Expenses									
Exploration	**43**	59	55	**–**	–	–	**–**	–	–
Purchases of crude oil and products	**2 837**	2 110	1 873	**19 212**	14 769	11 822	**1 191**	1 064	882
Production and manufacturing (d)	**1 931**	1 581	1 551	**1 203**	1 064	1 029	**195**	176	148
Selling and general (d) (e)	**36**	9	11	**1 096**	1 043	1 070	**81**	88	113
Federal excise tax	**–**	–	–	**1 278**	1 264	1 254	**–**	–	–
Depreciation and depletion	**651**	633	517	**230**	257	211	**12**	13	22
Financing costs (note 14)	**–**	1	1	**2**	2	2	**–**	–	–
Total expenses	**5 498**	4 393	4 008	**23 021**	18 399	15 388	**1 479**	1 341	1 165
Income before income taxes	**3 022**	2 232	1 640	**1 056**	812	670	**186**	168	67
Income taxes (note 4)									
Current	**955**	771	540	**409**	314	75	**69**	61	14
Deferred	**59**	(56)	(70)	**(47)**	(58)	133	**(4)**	(2)	9
Total income tax expense	**1 014**	715	470	**362**	256	208	**65**	59	23
Income before cumulative effect of accounting change	**2 008**	1 517	1 170	**694**	556	462	**121**	109	44
Cumulative effect of accounting change, after income tax	**–**	–	4	**–**	–	–	**–**	–	–
Net income	**2 008**	1 517	1 174	**694**	556	462	**121**	109	44
Cash flow from (used in) operating activities	**2 440**	2 331	1 720	**799**	908	659	**94**	126	36
Capital and exploration expenditures (f)	**937**	1 113	1 007	**478**	283	478	**19**	15	41
Property, plant and equipment									
Cost	**14 229**	13 538	12 610	**6 350**	6 078	6 069	**701**	682	609
Accumulated depreciation and depletion	**(7 780)**	7 337	6 813	**(3 037)**	2 959	2 856	**(474)**	459	401
Net property, plant and equipment (g) (h)	**6 449**	6 201	5 797	**3 313**	3 119	3 213	**227**	223	208
Total assets	**7 347**	6 866	6 417	**6 287**	5 555	5 287	**504**	497	440

	Corporate and other			Eliminations			Consolidated		
millions of dollars	**2005**	2004	2003	**2005**	2004	2003	**2005**	2004	2003
Revenues and other income									
External sales (b)	**–**	–	–				**27 797**	22 408	19 094
Intersegment sales (c)	**–**	–	–	**(6 074)**	(4 850)	(3 756)	**–**	–	–
Investment and other income	**26**	(35)	26				**417**	52	114
	26	(35)	26	**(6 074)**	(4 850)	(3 756)	**28 214**	22 460	19 208
Expenses									
Exploration	**–**	–	–				**43**	59	55
Purchases of crude oil and products	**–**	–	–	**(6 072)**	(4 849)	(3 754)	**17 168**	13 094	10 823
Production and manufacturing (d)	**–**	–	–	**(2)**	(1)	(2)	**3 327**	2 820	2 726
Selling and general (d) (e)	**364**	141	131				**1 577**	1 281	1 325
Federal excise tax	**–**	–	–				**1 278**	1 264	1 254
Depreciation and depletion	**2**	5	5				**895**	908	755
Financing costs (note 14)	**6**	4	(123)				**8**	7	(120)
Total expenses	**372**	150	13	**(6 074)**	(4 850)	(3 756)	**24 296**	19 433	16 818
Income before income taxes	**(346)**	(185)	13	**–**	–	–	**3 918**	3 027	2 390
Income taxes (note 4)									
Current	**(72)**	(43)	(19)				**1 361**	1 103	610
Deferred	**(51)**	(12)	7				**(43)**	(128)	79
Total income tax expense	**(123)**	(55)	(12)	**–**	–	–	**1 318**	975	689
Income before cumulative effect of accounting change	**(223)**	(130)	25				**2 600**	2 052	1 701
Cumulative effect of accounting change, after income tax	**–**	–	–				**–**	–	4
Net income	**(223)**	(130)	25	**–**	–	–	**2 600**	2 052	1 705
Cash flow from (used in) operating activities	**118**	(53)	(188)				**3 451**	3 312	2 227
Capital and exploration expenditures (f)	**41**	34	33				**1 475**	1 445	1 559
Property, plant and equipment									
Cost	**246**	205	145				**21 526**	20 503	19 433
Accumulated depreciation and depletion	**(103)**	101	96				**(11 394)**	10 856	10 166
Net property, plant and equipment (g) (h)	**143**	104	49				**10 132**	9 647	9 267
Total assets	**1 867**	1 407	501	**(423)**	(298)	(308)	**15 582**	14 027	12 337

(a) A significant portion of activities in the natural resources segment is conducted jointly with other companies. The segment includes the company's share of undivided interest in such activities as follows:

millions of dollars	2005	2004	2003
Total external and intersegment sales	**3 687**	2 744	2 494
Total expenses	**1 805**	1 598	1 577
Net income, after income tax	**1 249**	780	664
Total current assets	**305**	367	302
Long-term assets	**4 742**	4 140	3 553
Total current liabilities	**1 212**	948	913
Other long-term obligations	**524**	330	302
Cash flow from operating activities	**1 424**	1 188	883
Cash (used in) investing activities	**(403)**	(858)	(754)

(b) Includes export sales to the United States, as follows:

millions of dollars	2005	2004	2003
Natural resources	**1 633**	1 360	1 304
Petroleum products	**856**	1 074	792
Chemicals	**750**	678	567
Total export sales	**3 239**	3 112	2 663

(c) Intersegment sales are made essentially at prevailing market rates.

(d) During 2005, incentive compensation expenses previously included in the operating segments have been reclassified to the corporate and other segment. This change has the effect of isolating in one segment all incentive compensation expenses and improving the transparency of operating events in the operating segments. This change has no impact on consolidated total expenses, net income or the cash-flow profile of the company. Segmented results for 2004 and 2003 have been reclassified for comparative purposes.

(e) Consolidated selling and general expenses include delivery costs from final storage areas to customers of $310 million in 2005 (2004 – $307 million, 2003 – $285 million).

(f) There were no capital lease additions in 2005. Capital and exploration expenditures of the petroleum products segment included non-cash capital leases of $11 million in 2004.

(g) Includes property, plant and equipment under construction of $954 million (2004 – $1,983 million).

(h) Goodwill was not amortized in the past three years. All goodwill has been assigned to the petroleum products segment. There have been no goodwill acquisitions, impairment losses or write-offs due to sales in the past three years.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONTINUED)

3. Long-term debt

			2005	2004
Issued	Maturity date	Interest rate	Millions of dollars	
2003	$250 million due May 26, 2007 and $250 million due August 26, 2007 (a)	Variable	**500**	–
2003	January 19, 2008 (a)	Variable	**318**	318
Long-term debt (b)			**818**	318
Capital leases (c)			**45**	49
Total long-term debt (d) (e)			**863**	367

(a) These are long-term variable-rate loans from Exxon Overseas Corporation, an affiliated company of Exxon Mobil Corporation at interest equivalent to Canadian market rates. These loans were extended during 2005 for an additional two-year period to the maturity dates noted above.

(b) The average effective rate for the loans was 2.8 percent for 2005 (2004 – 2.5 percent).

(c) These obligations primarily relate to the capital lease for marine services, which are provided by the lessor commencing in 2004 for a period of 10 years, extendable for an additional five years. The average imputed rate was 10.5 percent in 2005 (2004 – 10.3 percent).

(d) Principal payments on long-term loans of $500 million are due in 2007 and $318 million are due in 2008. Principal payments on capital leases of approximately $4 million a year are due in each of the next five years.

(e) These amounts exclude that portion of long-term debt, totalling $477 million (2004 – $995 million), which matures within one year and is included in current liabilities.

4. Income taxes

millions of dollars	2005	2004	2003
Current income tax expense	**1 361**	1 103	610
Deferred income tax expense (a)	**(43)**	(128)	79
Total income tax expense (b)	**1 318**	975	689
Statutory corporate tax rate (percent)	**35.6**	37.0	38.5
Increase/(decrease) resulting from:			
Non-deductible royalty payments to governments	**3.8**	3.9	5.0
Resource allowance in lieu of royalty deduction	**(5.2)**	(7.0)	(7.5)
Manufacturing and processing credit	**–**	–	0.2
Enacted tax rate change	**–**	(1.8)	(3.1)
Other	**(0.6)**	0.1	(4.3)
Effective income tax rate	**33.6**	32.2	28.8

(a) The deferred income tax expense for the year is the difference in net deferred income tax liabilities at the beginning and end of the year. The provisions for deferred income taxes in 2005 did not have any net (charges)/credits for the effect of changes in tax laws and rates (2004 – $25 million; 2003 – $72 million).

(b) Cash outflow from income taxes, plus investment credits earned, was $1,024 million in 2005 (2004 – $641 million; 2003 – $573 million).

Deferred income taxes are based on differences between the accounting and tax values of assets and liabilities. These differences in value are remeasured at each year-end using the tax rates and tax laws expected to apply when those differences are realized or settled in the future. Components of deferred income tax liabilities and assets as at December 31 were:

millions of dollars	2005	2004
Depreciation and amortization	**1 470**	1 287
Successful drilling and land acquisitions	**319**	403
Pensions and benefits (a)	**(354)**	(343)
Site restoration	**(171)**	(158)
Net tax loss carryforwards (b)	**(49)**	(57)
Capitalized interest	**26**	26
Other	**(28)**	(3)
Deferred income tax liabilities	**1 213**	1 155
LIFO inventory valuation	**(487)**	(343)
Other	**(167)**	(105)
Deferred income tax assets	**(654)**	(448)
Valuation allowance	**–**	–
Net deferred income tax liabilities	**559**	707

(a) Income taxes charged directly to shareholders' equity related to minimum pension liability adjustment were $105 million benefit in 2005 (2004 – $41 million benefit; 2003 – $57 million expense).

(b) Tax losses can be carried forward indefinitely.

The operations of the company are complex, and related tax interpretations, regulations and legislation are continually changing. As a result, there are usually some tax matters in question. The company believes the provision made for income taxes is adequate.

5. Headquarters relocation

The relocation of the company's head office from Toronto, Ontario to Calgary, Alberta announced in September 2004 was completed as planned in August 2005.

Expenses in connection with the headquarters relocation activity are expected to total approximately $77 million ($52 million, after tax), about 85 percent of which has been recognized in 2005 in conjunction with employee relocations and compensation payments for employees who chose not to move. All such expenses are included in selling and general on the consolidated statement of income. The change in liabilities associated with the headquarters relocation is as follows:

millions of dollars	**2005**	2004
Beginning as of January 1	**–**	–
Additions	**65**	–
Settlement	**(48)**	–
Ending as of December 31	**17**	–

All operating segments are impacted by this activity, but the largest effects are in the petroleum products segment.

6. Employee retirement benefits

Retirement benefits, which cover almost all retired employees and their surviving spouses, include pension-income and certain health-care and life-insurance benefits. They are met through funded registered retirement plans and through unfunded supplementary benefits that are paid directly to recipients. Funding of registered retirement plans complies with federal and provincial pension regulations, and the company makes contributions to the plans based on an independent actuarial valuation.

Pension-income benefits consist mainly of company-paid defined benefit plans that are based on years of service and final average earnings. The company shares in the cost of health-care and life-insurance benefits. The company's benefit obligations are based on the projected benefit method of valuation that includes employee service to date and present compensation levels as well as a projection of salaries and service to retirement.

The expense and obligations for both funded and unfunded benefits are determined in accordance with United States generally accepted accounting principles and actuarial procedures. The process for determining retirement-income expense and related obligations includes making certain long-term assumptions regarding the discount rate, rate of return on plan assets and rate of compensation increases.

The total obligation for retirement benefits exceeded the fair value of plan assets at December 31, 2005 by $1,823 million (2004 – $1,712 million), of which $1,365 million (2004 – $1,276 million) was related to pension benefits and $458 million (2004 – $436 million) was related to other post-retirement benefits. The obligation and pension expense can vary significantly with changes in the assumptions used to estimate the obligation and the expected return on plan assets.

Details of the employee retirement benefits plans are as follows:

	Pension benefits			Other post-retirement benefits		
millions of dollars	**2005**	2004	2003	**2005**	2004	2003
Components of net benefit cost						
Current service cost	**86**	76	71	**7**	6	5
Interest cost	**239**	237	219	**24**	24	22
Expected return on plan assets	**(257)**	(223)	(179)	**–**	–	–
Amortization of prior service cost	**25**	27	25	**–**	–	–
Recognized actuarial loss/(gain)	**83**	68	69	**7**	4	3
Net benefit cost (a)	**176**	185	205	**38**	34	30
Change in benefit obligation						
Benefit obligation at January 1	**4 260**	3 761		**436**	382	
Current service cost	**86**	76		**7**	6	
Interest cost	**239**	237		**24**	24	
Amendments	**20**	37		**–**	–	
Actuarial loss/(gain)	**549**	405		**26**	47	
Other (b)	**(88)**	–		**(13)**	–	
Benefits paid	**(282)**	(256)		**(22)**	(23)	
Benefit obligation at December 31	**4 784**	4 260		**458**	436	
Accumulated benefit obligation at December 31	**4 261**	3 743				

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONTINUED)

	Pension benefits			Other post-retirement benefits		
millions of dollars	**2005**	2004	2003	**2005**	2004	2003
Change in plan assets						
Fair value of plan assets at January 1	**2 984**	2 786				
Actual return on plan assets	**370**	315				
Company contributions	**350**	114				
Payments directly to participants	**56**	25				
Other (b)	**(59)**	–				
Benefits paid	**(282)**	(256)				
Fair value of plan assets at December 31	**3 419**	2 984				
Excess/(deficiency) of plan assets over benefit obligations	**(1 365)**	(1 276)		**(458)**	(436)	
Unrecognized net actuarial loss/(gain) (c)	**1 397**	1 073		**101**	95	
Unrecognized prior service cost (c)	**94**	99		**–**	–	
Net amount recognized	**126**	(104)		**(357)**	(341)	
Amount recognized in the consolidated balance sheet consists of:						
Accrued benefit cost (note 7)	**(842)**	(759)		**(357)**	(341)	
Intangible assets	**93**	97		**–**	–	
Accumulated other nonowner changes in equity, minimum pension liability adjustment	**875**	558		**–**	–	
Net amount recognized	**126**	(104)		**(357)**	(341)	
Assumptions						
Assumptions used to determine benefit obligations at December 31 (percent)						
Discount rate (d)	**5.00**	5.75		**5.00**	5.75	
Long-term rate of compensation increase	**3.50**	3.50		**3.50**	3.50	
Assumptions used to determine net benefit cost for years ended December 31 (percent)						
Discount rate	**5.75**	6.25	6.25	**5.75**	6.25	6.25
Long-term rate of compensation increase	**3.50**	3.50	3.50	**3.50**	3.50	3.50
Long-term rate of return on funded assets	**8.25**	8.25	8.25	**–**	–	–

(a) A summary of net benefit cost with elements of employee future benefit costs before and after adjustments to recognize the long-term nature of employee benefit cost is shown in the table below:

	Pension benefits			Other post-retirement benefits		
millions of dollars	**2005**	2004	2003	**2005**	2004	2003
Components of net benefit cost						
Current service cost	**86**	76	71	**7**	6	5
Interest cost	**239**	237	219	**24**	24	22
Actual return on plan assets	**(370)**	(315)	(377)	**–**	–	–
Plan amendments for prior service	**20**	37	–	**–**	–	–
Actuarial loss/(gain)	**549**	405	171	**26**	47	19
Elements of employee future benefit costs before adjustments to recognize the long-term nature of employee future benefit costs	**524**	440	84	**57**	77	46
Adjustments to recognize the long-term nature of employee future benefit costs:						
Difference between expected return and actual return on plan assets for the year	**113**	92	198	**–**	–	–
Difference between amortization of prior service costs for the year and actual plan amendments for the year	**5**	(10)	25	**–**	–	–
Difference between actuarial (gain)/loss recognized for the year and actuarial (gain)/loss on accrued benefit obligation for the year	**(466)**	(337)	(102)	**(19)**	(43)	(16)
Net benefit cost	**176**	185	205	**38**	34	30

(b) These assets and liabilities relate to employees who provide computer and customer support services to the company. These employees were transferred to an affiliate of Exxon Mobil Corporation on January 1, 2005.

(c) Unrecorded assets/(liabilities) are amortized over the average remaining service life of employees, which for 2006 and subsequent years is 12.3 years (2005 – 12.6 years; 2004 – 13 years).

(d) The discount rate is determined using the yield for high quality, long-term Canadian corporate bonds at year-end with an average maturity (or duration) approximating that of the liabilities of the pension plan.

Plan assets

The company's pension plan asset allocation at December 31, 2004 and 2005, and target allocation for 2006 are as follows:

Asset category (percent)	Target allocation 2006	Percentage of plan assets at December 31 2005	2004
Equities	50 – 75	**62**	62
Fixed income	25 – 50	**38**	38
Other	0 – 10	**–**	–
Total		**100**	100

The company establishes the long-term expected rate of return by developing a forward-looking long-term return assumption for each asset class, taking into account factors such as the expected real return for the specific asset class and inflation. A single, long-term rate of return is then calculated as the weighted average of the target asset allocation and the long-term return assumption for each asset class. The 2005 long-term expected return of 8.25 percent used in the calculations of pension expense compares to an actual rate of return over the past decade of 10 percent.

The company's investment strategy for benefit plan assets reflects a long-term view, a careful assessment of the risks inherent in various asset classes and broad diversification to reduce the risk of the total portfolio. The company primarily invests in funds that follow an index-based strategy to achieve its objectives of diversifying risk while minimizing costs. The fund holds Imperial Oil Limited common shares primarily only to the extent necessary to replicate the relevant equity index. Asset-liability studies, or simulations of the interaction of cash flows associated with both assets and liabilities, are periodically used to establish the preferred target asset allocation. The target asset allocation for equity securities reflects the long-term nature of the liability. The balance of the fund is targeted to debt securities.

Cash flows

Benefit payments expected in:

millions of dollars	Pension benefits	Other post-retirement benefits
2006	238	23
2007	242	25
2008	246	26
2009	253	28
2010	260	29
Years 2011 – 2015	1 449	169

In 2006, the company expects to make cash contributions of about $395 million to its pension plan.

A summary of the change in other nonowner changes in equity related to the minimum pension liability adjustment is shown in the table below:

millions of dollars	Pension benefits 2005	2004	2003
Increase/(decrease) in accumulated other nonowner changes in equity, before tax	**(317)**	(143)	106
Deferred income tax (charge)/credit (note 4)	**105**	41	(57)
Increase/(decrease) in accumulated other nonowner changes in equity, after tax	**(212)**	(102)	49

A summary of pension plans with accumulated benefit obligations in excess of plan assets is shown in the table below:

millions of dollars	Pension benefits 2005	2004
For funded pension plans with accumulated benefit obligations in excess of plan assets:		
Projected benefit obligation	**4 403**	3 876
Accumulated benefit obligation	**3 908**	3 430
Fair value of plan assets	**3 419**	2 984
Accumulated benefit obligation less fair value of plan assets	**489**	446
For unfunded plans covered by book reserves:		
Projected benefit obligation	**381**	384
Accumulated benefit obligation	**353**	313

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONTINUED)

Additional expenses include contributions to the defined contribution plans, primarily the employee savings plan of $30 million in 2005 (2004 – $32 million; 2003 – $31 million).

The most recent independent actuarial valuation was as at December 31, 2004 and the next required valuation will be as of December 31, 2005. The measurement date used to determine the plan assets and the benefit obligations was December 31, 2005.

A one percent change in the assumptions at which retirement liabilities could be effectively settled is as follows:

Increase/(decrease) millions of dollars	One percent increase	One percent decrease
Rate of return on plan assets:		
Effect on net benefit costs	(35)	35
Discount rate:		
Effect on net benefit costs	(50)	60
Effect on benefit obligations	(605)	750
Rate of pay increases:		
Effect on net benefit costs	30	(35)
Effect on benefit obligations	180	(165)

For measurement purposes, a five percent health-care cost trend rate was assumed for 2005 and thereafter. A one percent change in the assumed health-care cost trend rate would have the following effects:

Increase/(decrease) millions of dollars	One percent increase	One percent decrease
Effect on service and interest cost components	4	(3)
Effect on other post-retirement benefits obligations	45	(40)

7. Other long-term obligations

millions of dollars	**2005**	2004
Employee retirement benefits (note 6) (a)	**1 152**	1 052
Asset retirement obligations and other environmental liabilities (b)	**423**	380
Other obligations	**153**	93
Total other long-term obligations	**1 728**	1 525

(a) Total recorded employee retirement benefits obligations also include $47 million in current liabilities (2004 – $48 million).

(b) Total asset retirement obligations and other environmental liabilities also include $76 million in current liabilities (2004 – $76 million). The estimated cash flows of asset retirement obligations have been discounted at six percent. The total undiscounted amount of the estimated cash flow required to settle the obligation is $1,717 million. Payments to settle the obligations occur on an ongoing basis and will continue over the lives of the operating assets, which can exceed 25 years. The change in asset retirement obligations liability is as follows:

millions of dollars	**2005**	2004
Asset retirement obligations liability at January 1	**328**	327
Additions	**53**	16
Accretion	**20**	22
Settlement	**(34)**	(37)
Asset retirement obligations liability at December 31	**367**	328

8. Derivatives and financial instruments

No significant energy derivatives, foreign-exchange forward contracts or currency and interest-rate swaps were transacted in the past three years. The company maintains a system of controls that includes a policy covering the authorization, reporting and monitoring of derivative activity.

The fair value of the company's financial instruments is determined by reference to various market data and other appropriate valuation techniques. There are no material differences between the fair values of the company's financial instruments from the recorded book value.

9. Stock-based incentive compensation programs

Stock-based incentive compensation programs are designed to retain selected employees, reward them for high performance and promote individual contribution to sustained improvement in the company's future business performance and shareholder value.

Incentive share units, deferred share units and restricted stock units

Incentive share units have value if the market price of the company's common shares when the unit is exercised exceeds the market value when the unit was issued. The issue price of incentive share units is the closing price of the company's shares on the Toronto Stock Exchange on the grant date. Up to 50 percent of the units may be exercised after one year from issuance; an additional 25 percent may be exercised after two years; and the remaining 25 percent may be exercised after three years. Incentive share units are eligible for exercise up to 10 years from issuance. The units may expire earlier if employment is terminated other than by retirement, death or disability.

The deferred share unit plan is made available to selected executives and nonemployee directors. The selected executives can elect to receive all or part of their performance bonus compensation in units and the nonemployee directors can elect to receive all or part of their directors' fees in units. The number of units granted to executives is determined by dividing the amount of the bonus elected to be received as deferred share units by the average of the closing prices of the company's shares on the Toronto Stock Exchange for the five consecutive trading days immediately prior to the date that the bonus would have been paid. The number of units granted to a nonemployee director is determined at the end of each calendar quarter by dividing the amount of director's fees for the calendar quarter that the nonemployee director elected to receive as deferred share units by the average closing price of the company's shares for the five consecutive trading days immediately prior to the last day of the calendar quarter. Additional units are granted based on the cash dividend payable on the company's shares divided by the average closing price immediately prior to the payment date for that dividend and multiplying the resulting number by the number of deferred share units held by the recipient.

Deferred share units cannot be exercised until after termination of employment with the company or resignation as a director and must be exercised no later than December 31 of the year following termination or resignation. On the exercise date, the cash value to be received for the units is determined based on the average closing price of the company's shares for the five consecutive trading days immediately prior to the date of exercise.

Under the restricted stock unit plan, each unit entitles the recipient to the conditional right to receive from the company, upon exercise, an amount equal to the closing price of the company's common shares on the Toronto Stock Exchange on the exercise dates. Fifty percent of the units are exercised three years following the grant date, and the remainder are exercised seven years following the grant date.

All units require settlement by cash payments with one exception. The restricted stock unit plan was amended for units granted in 2003 and future years by providing that the recipient may receive one common share of the company per unit or elect to receive the cash payment for the units to be exercised on the seventh anniversary of the grant date.

Incentive stock options

In April 2002, incentive stock options were granted for the purchase of the company's common shares at an exercise price of $46.50 per share. Up to 50 percent of the options may be exercised on or after January 1, 2003, a further 25 percent may be exercised on or after January 1, 2004, and the remaining 25 percent may be exercised on or after January 1, 2005. Any unexercised options expire after April 29, 2012. The company has not issued incentive stock options since 2002 and has no plans to issue incentive stock options in the future.

The company did not recognize compensation expense on the issuance of stock options because the exercise price was equal to the market value at the date of grant. If the fair-value-based method of accounting had been adopted, the impact on net income and earnings per share is shown in note 1 to the consolidated financial statements on page 42. The average fair value of each option granted during 2002 was $12.70. The fair value was estimated at the grant date using an option-pricing model with the following weighted average assumptions: risk-free interest rate of 5.7 percent, expected life of five years, volatility of 25 percent and a dividend yield of 1.9 percent.

The company has purchased shares on the market to fully offset the dilutive effects from the exercise of stock options. The practice is expected to continue.

A summary of the incentive compensation programs is as follows:

	Number of units				Expensed in period (millions of dollars)	Obligations outstanding at December 31 (millions of dollars)
	Granted	Exercised	Cancelled or adjusted	Outstanding at December 31		
Incentive share units						
2005	**–**	**(1 987 454)**	**(250)**	**3 278 719**	**230**	**299**
2004	–	(1 620 332)	(2 575)	5 266 423	94	245
2003	–	(1 142 145)	19 225	6 889 330	109	216
Deferred share units						
2005	**2 604**	**(5 225)**	**–**	**46 189**	**1**	**3**
2004	4 899	–	–	48 810	1	4
2003	8 253	(49 486)	(379)	43 911	1	3
Incentive stock options						
2005	**–**	**(813 450)**	**3 950**	**2 045 000**	**–**	**–**
2004	–	(274 250)	(7 400)	2 854 500	–	–
2003	–	(49 050)	(11 500)	3 136 150	–	–
Restricted stock units						
2005	**886 050**	**–**	**(9 465)**	**3 518 910**	**119**	**158**
2004	987 480	–	(5 710)	2 642 325	31	41
2003	872 085	(3 300)	(120)	1 660 555	11	11

10. Investment and other income

Investment and other income includes gains and losses on asset sales as follows:

millions of dollars	2005	2004	2003
Proceeds from asset sales	**440**	102	56
Book value of assets sold	**96**	59	44
Gain/(loss) on asset sales, before tax (a)	**344**	43	12
Gain/(loss) on asset sales, after tax (a)	**233**	32	10

(a) 2005 included a gain of $251 million ($163 million, after tax) from the sale of the wholly owned Redwater and interests in the North Pembina fields.

11. Commitments and contingent liabilities

At December 31, 2005, the company had commitments for non-cancellable operating leases and other long-term agreements that require the following minimum future payments:

millions of dollars	2006	2007	2008	2009	2010	After 2010
Operating leases (a)	48	46	44	41	37	57
Unconditional purchase obligations (b)	94	41	42	42	20	20
Firm capital commitments (c)	196	15	6	10	5	–
Other long-term agreements (d)	403	398	241	227	156	356

(a) Total rental expense incurred for operating leases in 2005 was $83 million (2004 – $104 million; 2003 – $124 million) which included minimum rental expenditures of $63 million (2004 – $77 million; 2003 – $93 million). Related rental income was not material.

(b) Unconditional purchase obligations are those long-term commitments that are non-cancellable or cancellable only under certain conditions. These mainly pertain to pipeline throughput agreements. Total payments under unconditional purchase obligations were $104 million in 2005 (2004 – $117 million; 2003 – $114 million).

(c) Firm capital commitments related to capital projects, shown on an undiscounted basis, totalled approximately $232 million at the end of 2005 (2004 – $171 million). The largest commitment outstanding at year-end 2005 was associated with the company's share of upstream capital projects of $72 million offshore Canada's East Coast.

(d) Other long-term agreements include primarily raw material supply and transportation services agreements. Total payments under other long-term agreements were $448 million in 2005 (2004 – $355 million; 2003 – $332 million). Payments under other long-term agreements related to the company's share of undivided interest in activities conducted jointly with other companies are approximately $95 million per year.

Other commitments arising in the normal course of business for operating and capital needs do not materially affect the company's consolidated financial position.

The company was contingently liable at December 31, 2005 for a maximum of $77 million relating to guarantees for purchasing operating equipment and other assets from its rural marketing associates upon expiry of the associate agreement or the resignation of the associate. The company expects that the fair value of the operating equipment and other assets so purchased would cover the maximum potential amount of future payment under the guarantees.

The company provides in its financial statements for asset retirement obligations and other environmental liabilities (see note 7 to the consolidated financial statements on page 53). Provision is not made with respect to those manufacturing, distribution and marketing facilities with indeterminate useful lives, because such potential obligations cannot be measured since it is not possible to estimate the settlement dates. These are primarily currently operated sites. These costs are not expected to have a material effect on the company's current consolidated financial position.

Various lawsuits are pending against Imperial Oil Limited and its subsidiaries. Based on a consideration of all relevant facts and circumstances, the company does not believe the ultimate outcome of any currently pending lawsuits against the company will have a material adverse effect on the company's operations or financial condition. There are no events or uncertainties known to management beyond those already included in reported financial information that would indicate a material change in future operating results or financial condition.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONTINUED)

12. Common shares

The number of authorized common shares of the company as at December 31, 2005 was 450,000,000, unchanged from January 1, 2004.

On February 2, 2006, the company proposed to subdivide the common shares of the company on a three-for-one basis. The proposed stock split is subject to shareholder and regulatory approvals.

From 1995 to 2004, the company purchased shares under ten 12-month normal course share purchase programs, as well as an auction tender. On June 23, 2005, another 12-month normal course share purchase program was implemented with an allowable purchase of 17.1 million shares (five percent of the total at June 21, 2005), less any shares purchased by the employee savings plan and company pension fund. The results of these activities are shown below.

Year	Purchased shares	Millions of dollars
1995 to 2003	218 920 739	5 968
2004	13 606 712	872
2005	**17 508 935**	**1 795**
Cumulative purchases to date	250 036 386	8 635

Exxon Mobil Corporation's participation in the above maintained its ownership interest in Imperial at 69.6 percent.

The company's common share activities are summarized below:

	Thousands of shares	Millions of dollars
Balance as at January 1, 2003	378 863	1 939
Issued for cash under the stock option plan	49	2
Purchases	(16 259)	(82)
Balance as at December 31, 2003	362 653	1 859
Issued for cash under the stock option plan	274	13
Purchases	(13 607)	(71)
Balance as at December 31, 2004	349 320	1 801
Issued for cash under the stock option plan	**814**	**38**
Purchases	**(17 509)**	**(92)**
Balance as at December 31, 2005	**332 625**	**1 747**

The following table provides the calculation of basic and diluted earnings per share:

	2005	2004	2003
Net income per common share – basic			
Income before cumulative effect of accounting change (millions of dollars)	**2 600**	2 052	1 701
Net income (millions of dollars)	**2 600**	2 052	1 705
Weighted average number of common shares outstanding (thousands of shares)	**341 373**	356 834	372 011
Net income per common share (dollars)			
Income before cumulative effect of accounting change	**7.62**	5.75	4.57
Cumulative effect of accounting change, after income tax	**–**	–	0.01
Net income	**7.62**	5.75	4.58
Net income per common share – diluted			
Income before cumulative effect of accounting change (millions of dollars)	**2 600**	2 052	1 701
Net income (millions of dollars)	**2 600**	2 052	1 705
Weighted average number of common shares outstanding (thousands of shares)	**341 373**	356 834	372 011
Effect of employee stock-based awards (thousands of shares)	**1 393**	818	143
Weighted average number of common shares outstanding, assuming dilution (thousands of shares)	**342 766**	357 652	372 154
Net income per common share (dollars)			
Income before cumulative effect of accounting change	**7.59**	5.74	4.57
Cumulative effect of accounting change	**–**	–	0.01
Net income	**7.59**	5.74	4.58

13. Miscellaneous financial information

In 2005, net income included an after-tax gain of $5 million (2004 – $23 million gain; 2003 – $9 million gain) attributable to the effect of changes in last-in, first-out (LIFO) inventories. The replacement cost of inventories was estimated to exceed their LIFO carrying values at December 31, 2005 by $1,429 million (2004 – $1,013 million). Inventories of crude oil and products at year-end consisted of the following:

millions of dollars	**2005**	2004
Crude oil	**174**	165
Petroleum products	**234**	190
Chemical products	**63**	59
Natural gas and other	**10**	18
Total inventories of crude oil and products	**481**	432

Research and development costs in 2005 were $68 million (2004 – $70 million; 2003 – $63 million) before investment tax credits earned on these expenditures of $10 million (2004 – $7 million; 2003 – $10 million). The net costs are included in expenses due to the uncertainty of future benefits.

Cash flow from operating activities included dividends of $21 million received from equity investments in 2005 (2004 – $18 million; 2003 – $15 million).

14. Financing costs

millions of dollars	**2005**	2004	2003
Debt-related interest	**45**	37	38
Capitalized interest	**(41)**	(34)	(33)
Net interest expense	**4**	3	5
Other interest	**4**	4	4
Total interest expense (a)	**8**	7	9
Foreign-exchange expense/(gain) on long-term debt	**–**	–	(129)
Total financing costs	**8**	7	(120)

(a) Cash interest payments in 2005 were $45 million (2004 – $41 million; 2003 – $38 million). The weighted average interest rate on short-term borrowings in 2005 was 2.7 percent (2004 – 2.3 percent).

15. Transactions with related parties

Revenues and expenses of the company also include the results of transactions with Exxon Mobil Corporation and affiliated companies (ExxonMobil) in the normal course of operations. These were conducted on terms as favourable as they would have been with unrelated parties and primarily consisted of the purchase and sale of crude oil and petroleum and chemical products, as well as transportation, technical and engineering services. Transactions with ExxonMobil also included amounts paid and received in connection with the company's participation in a number of natural resources activities conducted jointly in Canada. The company has existing agreements with affiliates of Exxon Mobil Corporation to provide computer and customer support services to the company and to share common business and operational support services that allow the companies to consolidate duplicate work and systems. During 2005, the company and an affiliate of Exxon Mobil Corporation in Canada agreed to operate their respective Western Canada production organizations as one single organization. Under the consolidation, Imperial will operate all Western Canada properties. There are no asset ownership changes. The amounts paid or received have been reflected in the consolidated statement of income as shown below.

millions of dollars	**2005**	2004	2003
Total revenues and other income	**1 357**	1 176	950
Purchases of crude oil and products	**3 599**	3 133	2 464
Total expenses	**175**	43	14

Accounts payable due to Exxon Mobil Corporation at December 31, 2005 with respect to the above transactions, were $224 million (2004 – $67 million).

Certain charges from ExxonMobil have been capitalized; they are not material in the aggregate.

The company borrowed $818 million (Cdn) from Exxon Overseas Corporation under two long-term loan agreements as presented in note 3. Interest on the loans in 2005 was $23 million (2004 – $20 million).

During 2004, the company extended loans of $32 million to Montreal Pipe Line Limited, in which the company has an equity interest, for financing of the equity company's capital expenditure programs and working capital requirements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONTINUED)

16. Net payments/payables to governments

millions of dollars	**2005**	2004	2003
Current income tax expense (note 4)	**1 361**	1 103	610
Federal excise tax	**1 278**	1 264	1 254
Property taxes included in expenses	**99**	85	80
Payroll and other taxes included in expenses	**52**	50	52
GST/QST/HST collected (a)	**2 703**	2 297	2 015
GST/QST/HST input tax credits (a)	**(2 344)**	(1 948)	(1 705)
Other consumer taxes collected for governments	**1 613**	1 670	1 662
Crown royalties	**620**	472	418
Total paid or payable to governments	**5 382**	4 993	4 386
Less investment tax credits and other receipts	**9**	14	30
Net paid or payable to governments	**5 373**	4 979	4 356
Net paid or payable to:			
Federal government	**2 736**	2 472	2 061
Provincial governments	**2 538**	2 422	2 215
Local governments	**99**	85	80
Net paid or payable to governments	**5 373**	4 979	4 356

(a) The abbreviations refer to the federal goods and services tax, the Quebec sales tax and the federal/provincial harmonized sales tax, respectively. The HST is applicable in the provinces of Nova Scotia, New Brunswick and Newfoundland and Labrador.

17. Differences between United States and Canadian generally accepted accounting principles

Effective 2004, the company prepares its financial statements in accordance with the generally accepted accounting principles (GAAP) of the United States. Prior to 2004, the company's financial statements were prepared in conformity with Canadian GAAP.

I. The comparative Canadian GAAP financial statements as previously reported are provided below:

Consolidated Statement of Income (Canadian GAAP)

millions of dollars For the years ended December 31	2004	2003
Revenues and other income		
Operating revenues (a) (b)	22 408	19 094
Investment and other income	52	114
Total revenues and other income	22 460	19 208
Expenses		
Exploration	59	55
Purchases of crude oil and products	13 094	10 823
Production and manufacturing	2 820	2 726
Selling and general	1 281	1 325
Federal excise tax (a)	1 264	1 254
Depreciation and depletion	903	750
Financing costs	41	(87)
Total expenses	19 462	16 846
Income before income taxes	2 998	2 362
Income taxes	965	680
Net income	2 033	1 682

(a) Operating revenues include federal excise tax of $1,264 million in 2004 (2003 – $1,254 million).

(b) Operating revenues include amounts for purchase/sale contracts with the same counterparty (associated costs are included in "purchases of crude oil and products") of $3,584 million in 2004 (2003 — $2,851 million).

Certain figures have been reclassified in the above financial statement.

Consolidated Statement of Cash Flows (Canadian GAAP)

millions of dollars inflow/(outflow) For the years ended December 31	2004	2003
Operating activities		
Net income	2 033	1 682
Adjustments for non-cash items:		
Depreciation and depletion	903	750
(Gain)/loss on asset sales, after tax	(32)	(10)
Deferred income taxes and other	(100)	(68)
Changes in operating assets and liabilities:		
Accounts receivable	(311)	33
Inventories and prepaids	(32)	31
Income taxes payable	462	38
Accounts payable	308	74
All other items – net (a)	47	(336)
Cash from operating activities	3 278	2 194
Investing activities		
Additions to property, plant and equipment and intangibles	(1 342)	(1 449)
Proceeds from asset sales	102	56
Loans to equity company	(32)	–
Cash from (used in) investing activities	(1 272)	(1 393)
Financing activities		
Short-term debt – net	9	–
Long-term debt issued	–	818
Repayment of long-term debt	(8)	(818)
Issuance of common shares under stock option plan	13	2
Common shares purchased (note 12)	(872)	(799)
Dividends paid	(317)	(322)
Cash used in financing activities	(1 175)	(1 119)
Increase (decrease) in cash	831	(318)
Cash at beginning of year	448	766
Cash at end of year (b)	1 279	448

(a) Includes contribution to registered pension plans of $114 million in 2004 (2003 – $511 million).

(b) Cash is composed of cash in bank and cash equivalents at cost. Cash equivalents are all highly liquid securities with a maturity of three months or less when purchased.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONTINUED)

Consolidated Balance Sheet (Canadian GAAP)

millions of dollars At December 31	2004
Assets	
Current assets	
Cash	1 279
Accounts receivable, less estimated doubtful amounts	1 626
Inventories of crude oil and products (note 13)	432
Materials, supplies and prepaid expenses	112
Deferred income tax assets (note 4)	448
Total current assets	3 897
Investments and other long-term assets	270
Property, plant and equipment, less accumulated depreciation and depletion	9 569
Goodwill (note 2)	204
Other intangible assets, net	52
Total assets	13 992
Liabilities	
Current liabilities	
Short-term debt	81
Accounts payable and accrued liabilities (note 15)	2 525
Income taxes payable	1 057
Current portion of long-term debt	995
Total current liabilities	4 658
Long-term debt (note 3)	367
Other long-term obligations	1 010
Deferred income tax liabilities	1 319
Commitments and contingent liabilities (note 11)	
Total liabilities	7 354
Shareholders' equity	
Common shares at stated value (note 12)	1 801
Earnings reinvested	4 837
Total shareholders' equity	6 638
Total liabilities and shareholders' equity	13 992

II. A reconciliation of the differences between GAAP in Canada and in the United States as they apply to the company is provided below:

Consolidated statement of income	Reported under U.S. GAAP	Increase/(decrease) due to Capitalized interest	Increase/(decrease) due to Accounting change	Reported under Canadian GAAP
Net income for 2005 (millions of dollars)	**2 600**	**(23)**	**–**	**2 577**
Net income per common share (dollars)				
Basic	**7.62**	**0.07**	**–**	**7.55**
Diluted	**7.59**	**0.07**	**–**	**7.52**
Net income for 2004 (millions of dollars)	2 052	(19)	–	2 033
Net income per common share (dollars)				
Basic	5.75	(0.05)	–	5.70
Diluted	5.74	(0.05)	–	5.69
Net income for 2003 (millions of dollars)	1 705	(19)	(4)	1 682
Net income per common share (dollars)				
Basic	4.58	(0.05)	(0.01)	4.52
Diluted	4.58	(0.05)	(0.01)	4.52

Consolidated statement of cash flows millions of dollars	Reported under U.S. GAAP	Increase/(decrease) due to Capitalized interest	Reported under Canadian GAAP
Cash from operating activities for 2005	**3 451**	**(41)**	**3 410**
Cash from/(used in) investing activities for 2005	**(992)**	**41**	**(951)**
Cash from operating activities for 2004	3 312	(34)	3 278
Cash from/(used in) investing activities for 2004	(1 306)	34	(1 272)
Cash from operating activities for 2003	2 227	(33)	2 194
Cash from/(used in) investing activities for 2003	(1 426)	33	(1 393)

Consolidated balance sheet millions of dollars	Reported under U.S. GAAP	Increase/(decrease) due to Capitalized interest	Increase/(decrease) due to Minimum pension liabilities	Reported under Canadian GAAP
As at December 31, 2005				
Investments and other long-term assets	**127**	**–**	**365**	**492**
Property, plant and equipment, net	**10 132**	**(116)**	**–**	**10 016**
Other intangible assets	**153**	**–**	**(93)**	**60**
Total assets	**15 582**	**(116)**	**272**	**15 738**
Other long-term obligations	**1 728**	**–**	**(604)**	**1 124**
Deferred income tax liabilities	**1 213**	**(41)**	**296**	**1 468**
Earnings reinvested	**5 466**	**(75)**	**–**	**5 391**
Accumulated other nonowner changes in equity	**(580)**	**–**	**580**	**–**
Total liabilities and shareholders' equity	**15 582**	**(116)**	**272**	**15 738**
As at December 31, 2004				
Investments and other long-term assets	130	–	140	270
Property, plant and equipment, net	9 647	(78)	–	9 569
Other intangible assets	149	–	(97)	52
Total assets	14 027	(78)	43	13 992
Other long-term obligations	1 525	–	(515)	1 010
Deferred income tax liabilities	1 155	(26)	190	1 319
Earnings reinvested	4 889	(52)	–	4 837
Accumulated other nonowner changes in equity	(368)	–	368	–
Total liabilities and shareholders' equity	14 027	(78)	43	13 992

Under U.S. GAAP, interest costs related to major capital projects under construction are required to be capitalized as part of property, plant and equipment. Under Canadian GAAP, the company did not capitalize interest costs for the same projects.

Under U.S. GAAP, the cumulative effect of change for the adoption of the standard on accounting for asset retirement obligations in 2003 was reflected in the consolidated net income for 2003. Under Canadian GAAP, financial statements of prior periods were restated to reflect the effect of the same accounting change.

Under U.S. GAAP, the accumulated benefit obligation (ABO) is the actuarial present value of benefits attributed to employee service rendered up to the end of the year and is based on current compensation levels. Since the amount by which the ABO less the fair value of plan assets was greater than the liability previously recognized in the consolidated balance sheet, an additional minimum pension liability was required. The minimum pension liability has no impact on net income and because this adjustment was non-cash, its effect has been excluded from the accompanying consolidated statement of cash flows. No such adjustment is required under Canadian GAAP.

Natural resources segment – Supplemental information (unaudited)

Pages 63 to 65 provide information about the natural resources segment (see note 2, page 46). The information excludes items not related to oil and natural gas extraction such as administrative and general expenses, pipeline operations, gas plant processing fees and gains or losses on asset sales.

In addition to proved oil and gas reserves, the company has a 25 percent interest in proven synthetic crude oil reserves in the Syncrude project. For internal management purposes, the company views these reserves and their development as an integral part of its total natural resources operations. However, for financial reporting purposes, these reserves are required to be reported separately from the oil and gas reserves as shown on page 65.

The synthetic crude oil reserves are not considered in the standardized measure of discounted future cash flows for oil and gas reserves on page 64. The company's share of Syncrude results of operations, capital and exploration expenditures and property, plant and equipment is also excluded from the following tables on this page.

Results of operations

	Oil and gas		
millions of dollars	**2005**	2004	2003
Sales to customers (a)	**2 739**	2 160	2 067
Intersegment sales (a) (b)	**1 013**	976	665
	3 752	3 136	2 732
Production expenses	**1 035**	870	883
Exploration expenses	**31**	44	55
Depreciation and depletion	**583**	565	463
Income taxes	**716**	547	376
Results of operations	**1 387**	1 110	955

Capital and exploration expenditures

	Oil and gas		
millions of dollars	**2005**	2004	2003
Property costs (c)			
Proved	**–**	–	–
Unproved	**7**	1	2
Exploration costs	**37**	43	55
Development costs	**330**	408	339
Total capital and exploration expenditures	**374**	452	396

Property, plant and equipment

	Oil and gas	
millions of dollars	**2005**	2004
Property costs (c)		
Proved	**3 231**	3 328
Unproved	**162**	141
Producing assets	**6 111**	6 099
Support facilities	**174**	122
Incomplete construction	**432**	235
Total cost	**10 110**	9 925
Accumulated depreciation and depletion	**6 934**	6 514
Net property, plant and equipment	**3 176**	3 411

(a) Sales to customers or intersegment sales do not include the sale of natural gas and natural gas liquids purchased for resale, as well as royalty payments. These items are reported gross in note 2 in "external sales", "intersegment sales" and in "purchases of crude oil and products".

(b) Sales of crude oil to consolidated affiliates are at market value, using posted field prices. Sales of natural gas liquids to consolidated affiliates are at prices estimated to be obtainable in a competitive, arm's-length transaction.

(c) "Property costs" are payments for rights to explore for petroleum and natural gas and for purchased reserves (acquired tangible and intangible assets such as gas plants, production facilities and producing-well costs are included under "producing assets"). "Proved" represents areas where successful drilling has delineated a field capable of production. "Unproved" represents all other areas.

NATURAL RESOURCES SEGMENT – SUPPLEMENTAL INFORMATION (CONTINUED)

Standardized measure of discounted future cash flows

As required by the Financial Accounting Standards Board, the standardized measure of discounted future net cash flows is computed by applying year-end prices, costs and legislated tax rates and a discount factor of 10 percent to net proved reserves. The standardized measure includes costs for future dismantlement, abandonment and rehabilitation obligations. The company believes the standardized measure does not provide a reliable estimate of the company's expected future cash flows to be obtained from the development and production of its oil and gas properties or of the value of its proved oil and gas reserves. The standardized measure is prepared on the basis of certain prescribed assumptions, including year-end prices, which represent a single point in time and therefore may cause significant variability in cash flows from year to year as prices change. The table below excludes the company's interest in Syncrude.

Standardized measure of discounted future net cash flows related to proved oil and gas reserves

	Oil and gas		
millions of dollars	**2005**	2004	2003
Future cash flows	**21 911**	11 625	27 611
Future production costs	**(11 376)**	(3 123)	(10 871)
Future development costs	**(2 039)**	(1 492)	(3 084)
Future income taxes	**(2 777)**	(2 260)	(5 543)
Future net cash flows	**5 719**	4 750	8 113
Annual discount of 10 percent for estimated timing of cash flows	**(1 405)**	(1 433)	(3 375)
Discounted future cash flows	**4 314**	3 317	4 738

Changes in standardized measure of discounted future net cash flows related to proved oil and gas reserves

	Oil and gas		
millions of dollars	**2005**	2004	2003
Balance at beginning of year	**3 317**	4 738	8 201
Changes resulting from:			
Sales and transfers of oil and gas produced, net of production costs	**(2 650)**	(2 240)	(2 075)
Net changes in prices, development costs and production costs	**3 343**	(3 692)	(4 395)
Extensions, discoveries, additions and improved recovery, less related costs	**(513)**	(43)	22
Development costs incurred during the year	**272**	345	281
Revisions of previous quantity estimates	**660**	1 838	(368)
Accretion of discount	**417**	663	1 108
Net change in income taxes	**(532)**	1 708	1 964
Net change	**997**	(1 421)	(3 463)
Balance at end of year	**4 314**	3 317	4 738

Net proved developed and undeveloped reserves (a)

The information below describes changes during the years and balances of proved oil and gas and synthetic crude oil reserves at year-end 2003, 2004 and 2005. The definitions used for oil and gas reserves are in accordance with the U.S. Securities and Exchange Commission's (SEC) Rule 4-10 (a) of Regulation S-X, paragraphs (2), (3) and (4).

Crude oil and natural gas reserve estimates, excluding Syncrude, are based on geological and engineering data, which have demonstrated with reasonable certainty that these reserves are recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Reserves of crude oil at Cold Lake are those estimated to be recoverable from the Leming plant and commercial phases. Estimates of synthetic crude oil reserves are based on detailed geological and engineering assessments of in-place crude bitumen volumes, the mining plan, historical extraction recovery and upgrading yield factors, installed plant operating capacity and operating approval limits.

Based on SEC regulatory guidance, the company has reported 2004 and 2005 reserves on the basis of December 31 prices and costs respectively ("year-end prices").

The use of year-end prices for reserves estimation introduces short-term price volatility into the process since annual adjustments are required based on prices occurring on a single day. The company believes that this approach is inconsistent with the long-term nature of the natural resources business where production from individual projects often spans multiple decades. The use of prices from a single date is not relevant to the investment decisions made by the company and annual variations in reserves based on such year-end prices are not of consequence to how the business is actually managed.

The impact of year-end prices on reserves estimation is most clearly shown at Cold Lake where proved bitumen and associated natural gas reserves were reduced by about 137 million oil-equivalent barrels as a result of using December 31, 2005 prices, which were seasonally low. Prices quickly rebounded from December 31 and through January 2006 returned to levels that have restored the reserves to the proved category, repeating the same reserves rebooking situation as in January 2005.

(a) Net reserves are the company's share of reserves after deducting the shares of mineral owners or governments or both. All reported reserves are located in Canada. Reserves of natural gas are calculated at a pressure of 14.73 pounds per square inch at 60°F.

Revisions can include upward or downward changes in previously estimated volumes of proved reserves for existing fields due to the evaluation or revaluation of already available geologic, reservoir or production data; new geologic, reservoir or production data; or changes to underlying price assumptions used in the determination of reserves. This category can also include changes associated with the performance of improved recovery projects and significant changes in either development strategy or production equipment/facility capacity. During the past five years, revisions averaged an upward adjustment of eight million oil-equivalent barrels per year.

Net proved reserves are determined by deducting the estimated future share of mineral owners or governments or both. For conventional crude oil (excluding enhanced oil-recovery projects) and natural gas, net proved reserves are based on estimated future royalty rates representative of those existing as of the date the estimate is made. Actual future royalty rates may vary with production and price. For enhanced oil-recovery projects, Syncrude and Cold Lake, net proved reserves are based on the company's best estimate of average royalty rates over the life of each project. Actual future royalty rates may vary with production, price and costs.

Reserves data do not include certain resources of crude oil and natural gas such as those discovered in the Beaufort Sea-Mackenzie Delta and the Arctic islands, or the resources contained in oil sands other than reserves attributable to Syncrude, the Cold Lake Leming plant and commercial phases of Cold Lake production operations.

Oil-equivalent barrels (OEB) may be misleading, particularly if used in isolation. An OEB conversion ratio of 6,000 cubic feet to one barrel on an energy-equivalent conversion method is primarily applicable at the burner tip and does not represent a value equivalency at the well head. No independent qualified reserves evaluator or auditor was involved in the preparation of the reserves data.

	Crude oil and NGLs millions of barrels			Natural gas billions of cubic feet	Synthetic crude oil millions of barrels
	Conventional	Cold Lake	Total		Syncrude
Beginning of year 2003	146	801	947	1 224	800
Revisions and improved recovery	1	5	6	(40)	–
(Sale)/purchase of reserves in place	–	–	–	–	–
Discoveries and extensions	–	–	–	6	–
Production	(21)	(43)	(64)	(167)	(19)
End of year 2003	126	763	889	1 023	781
Revisions and improved recovery	6	(20)	(14)	57	(3)
(Sale)/purchase of reserves in place	–	–	–	(13)	–
Discoveries and extensions	–	–	–	3	–
Production	(22)	(41)	(63)	(190)	(21)
Total before year-end price/cost revisions	110	702	812	880	757
Year-end price/cost revisions	5	(470)	(465)	(89)	–
End of year 2004	115	232	347	791	757
Remove 2004 year-end price/cost revisions	(5)	470	465	89	–
Total before 2004 year-end price/cost revisions	110	702	812	880	757
Revisions and improved recovery	**(1)**	**9**	**8**	**65**	**–**
(Sale)/purchase of reserves in place	**(12)**	**–**	**(12)**	**(6)**	**–**
Discoveries and extensions	**–**	**17**	**17**	**14**	**–**
Production	**(20)**	**(45)**	**(65)**	**(188)**	**(19)**
Total before 2005 year-end price/cost revisions	**77**	**683**	**760**	**765**	**738**
Year-end price/cost revisions	**6**	**(132)**	**(126)**	**(18)**	**–**
End of year 2005	**83**	**551**	**634**	**747**	**738**

Share ownership, trading and performance

	2005	2004	2003	2002	2001
Share ownership					
Average number outstanding, weighted monthly (thousands)	**341 373**	356 834	372 011	378 875	393 121
Number of shares outstanding at December 31 (thousands)	**332 625**	349 320	362 653	378 863	379 159
Shares held in Canada at December 31 (percent)	**13.8**	14.6	15.2	15.8	15.9
Number of registered shareholders at December 31 (a)	**14 096**	14 953	15 516	15 988	16 483
Number of shareholders registered in Canada	**12 331**	13 088	13 601	14 014	14 358
Shares traded (thousands)	**119 211**	93 778	94 063	83 019	129 285
Share prices (dollars)					
Toronto Stock Exchange					
High	**137.37**	73.65	58.22	49.38	46.50
Low	**67.51**	56.42	43.20	38.51	34.05
Close at December 31	**115.41**	71.15	57.53	44.86	44.31
American Stock Exchange ($U.S.)					
High	**117.41**	62.45	44.75	31.85	29.45
Low	**54.80**	42.34	28.25	24.00	22.59
Close at December 31	**99.60**	59.38	44.42	28.70	27.88
Net income per share (dollars)					
– basic	**7.62**	5.75	4.58	3.20	3.11
– diluted	**7.59**	5.74	4.58	3.20	3.11
Price ratios at December 31					
Share price to net earnings (b)	**15.2**	12.4	12.6	14.0	14.2
Dividends declared (c)					
Total (millions of dollars)	**320**	314	323	318	324
Per share (dollars)	**0.94**	0.88	0.87	0.84	0.83

(a) Exxon Mobil Corporation owns 69.6 percent of Imperial's shares.

(b) Closing share price at December 31 at the Toronto Stock Exchange, divided by net income per share – diluted.

(c) The fourth-quarter dividend is paid on January 1 of the succeeding year.

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 a Canadian nonresident withholding tax of 15 percent.

The withholding tax is reduced to five percent on dividends paid to a corporation resident in the United States that owns at least 10 percent of the voting shares of the company.

Imperial Oil Limited is a qualified foreign corporation for purposes of the reduced U.S. capital gains tax rates (15 percent and five percent for certain individuals) which are applicable to dividends paid by U.S. domestic corporations and qualified foreign corporations.

There is no Canadian tax on gains from selling shares or debt instruments owned by nonresidents not carrying on business in Canada.

Valuation day price

For capital gains purposes, Imperial's common shares were quoted at $10.50 a share on December 31, 1971 and $15.29 on February 22, 1994. Both amounts are restated for the 1998 three-for-one share split.

Employees

	2005	2004	2003	2002	2001
Number of employees at December 31	**5 096**	6 083	6 256	6 460	6 740

Quarterly financial and stock-trading data (a)

	2005 three months ended				2004 three months ended			
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	Mar. 31	June 30	Sept. 30	Dec. 31
Financial data, under U.S. GAAP (millions of dollars)								
Total revenues and other income	**5 958**	**6 802**	**7 711**	**7 743**	5 067	5 466	5 814	6 113
Total expenses	**5 370**	**5 989**	**6 753**	**6 184**	4 347	4 767	4 986	5 333
Income before income taxes	**588**	**813**	**958**	**1 559**	720	699	828	780
Income taxes	**(195)**	**(274)**	**(306)**	**(543)**	(254)	(195)	(284)	(242)
Net income	**393**	**539**	**652**	**1 016**	466	504	544	538
Segmented net income, under U.S. GAAP (millions of dollars) (b)								
Natural resources	**276**	**469**	**592**	**671**	324	377	417	399
Petroleum products	**166**	**94**	**171**	**263**	144	123	111	178
Chemicals	**44**	**33**	**12**	**32**	13	32	33	31
Corporate and other	**(93)**	**(57)**	**(123)**	**50**	(15)	(28)	(17)	(70)
Net income	**393**	**539**	**652**	**1 016**	466	504	544	538
Per-share information, under U.S. GAAP (dollars)								
Net earnings – basic	**1.13**	**1.56**	**1.92**	**3.01**	1.29	1.40	1.53	1.53
Net earnings – diluted	**1.12**	**1.56**	**1.91**	**3.00**	1.29	1.40	1.53	1.52
Dividends (declared quarterly)	**0.22**	**0.24**	**0.24**	**0.24**	0.22	0.22	0.22	0.22
Share prices (dollars) (c)								
Toronto Stock Exchange								
High	**94.33**	**104.97**	**137.37**	**136.18**	64.45	64.25	66.76	73.65
Low	**67.51**	**82.10**	**100.00**	**96.85**	56.42	58.40	59.50	65.28
Close	**92.02**	**102.02**	**134.01**	**115.41**	58.87	62.40	65.48	71.15
American Stock Exchange ($U.S.)								
High	**77.20**	**85.15**	**117.41**	**116.78**	48.70	47.13	52.22	62.45
Low	**54.80**	**64.70**	**82.38**	**82.41**	42.34	43.17	45.50	51.43
Close	**76.14**	**83.31**	**115.06**	**99.60**	44.84	46.82	51.71	59.38
Shares traded (thousands) (d)	**25 982**	**29 667**	**30 595**	**32 968**	26 559	21 640	22 132	23 447

(a) Quarterly data has not been audited by the company's independent auditors.

(b) Beginning in the third quarter of 2005, incentive compensation expenses previously included in the operating segments are now reported in the "corporate and other" segment. Segmented quarterly results for 2004 and for the first and second quarters of 2005 have been reclassified for comparative purposes. This change has no impact on consolidated total expenses, net income or the cash flow profile of the company.

(c) Imperial's shares are listed on the Toronto Stock Exchange and are admitted to unlisted trading on the American Stock Exchange in New York. The symbol on these exchanges for Imperial's common shares is IMO. Share prices were obtained from stock exchange records.

(d) The number of shares traded is based on transactions on the above stock exchanges.

Dividend and share-purchase information

	2nd quarter, 2006	**3rd quarter, 2006**	**4th quarter, 2006**	**1st quarter, 2007**
Declaration date	May 23, 2006	August 29, 2006	November 23, 2006	February 14, 2007
Dividend record date	June 6, 2006	September 8, 2006	December 5, 2006	March 2, 2007
Dividend payment date	July 1, 2006	October 1, 2006	January 1, 2007	April 1, 2007
Share-purchase cutoff date (cheques for share purchase must be dated and received no later than)	June 16, 2006	September 15, 2006	December 13, 2006	March 16, 2007
Investment date (dividend reinvestment and share purchase funds are invested by the company on)	July 4, 2006	October 2, 2006	January 2, 2007	April 2, 2007

The declaration of dividends and the dates shown are subject to change by the board of directors.
The company reserves the right to amend, suspend or terminate the dividend reinvestment and share purchase plan at any time.
Share purchase cheques should be made payable to CIBC Mellon Trust Company.
Dividend cheques are normally mailed three to five days prior to payment dates.
Quarterly statements for dividend reinvestment and share purchase plan participants are normally mailed two weeks after the investment dates.

Information for investors

Head office
Imperial Oil Limited
P.O. Box 2480, Station 'M'
Calgary, Alberta, Canada T2P 3M9

Annual meeting
The annual meeting of shareholders will be held on Tuesday, May 2, 2006, at 10:30 a.m. local time at the TELUS Convention Centre, 120 Ninth Avenue S.E., Calgary, Alberta, Canada.

Shareholder account matters
To change your address, transfer shares, eliminate multiple mailings, elect to receive dividends in U.S. funds or have dividends deposited directly into accounts at financial institutions in Canada that provide electronic fund-transfer services, enrol in the dividend reinvestment and share purchase plan, or enrol for electronic delivery of shareholder reports, please contact CIBC Mellon Trust Company.

CIBC Mellon Trust Company
P.O. Box 7010
Adelaide Street Postal Station
Toronto, Ontario, Canada M5C 2W9
Telephone: 1-800-387-0825 (from Canada or U.S.A.)
or 416-643-5500
Fax: 416-643-5501
E-mail: inquiries@cibcmellon.com
www.cibcmellon.com

United States resident shareholders may transfer their shares through Mellon Investor Services LLC.

Mellon Investor Services LLC
480 Washington Boulevard
Jersey City, New Jersey, U.S.A. 07310-1900
Telephone: 1-800-526-0801

Dividend reinvestment and share-purchase plan
This plan provides shareholders with two ways to add to their shareholdings at a reduced cost. The plan enables shareholders to reinvest their cash dividends in additional shares at an average market price. Shareholders can also invest between $50 and $5,000 each calendar quarter in additional shares at an average market price.

Funds directed to the dividend reinvestment and share-purchase plan are used to buy existing shares on a stock exchange rather than newly issued shares.

Imperial online
Imperial's website contains a variety of corporate and investor information, including:
- current stock prices
- annual and interim reports
- Form 10-K
- *Information for Investors* (a factbook that describes the company and its operations in detail)
- investor presentations
- earnings and other news releases
- historical dividend information
- corporate citizenship practices

www.imperialoil.ca

Investor information
Information is also available by writing to the investor relations manager at Imperial's head office or by:
Telephone: 403-237-4538
Fax: 403-237-2081

Other contact numbers
Customer and other inquiries:
Telephone: 1-800-567-3776
Fax: 1-800-367-0585

Corporate secretary
Telephone: 403-237-2915
Fax: 403-237-2490

Version française du rapport
Pour obtenir la version française du rapport de la Compagnie Pétrolière Impériale Ltée, veuillez écrire à la division des Relations avec les investisseurs, Compagnie Pétrolière Impériale Ltée, P.O. Box 2480 Station 'M', Calgary, Alberta, Canada T2P 3M9.

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Directors, senior management and officers

Board of directors

(Standing, from left to right)

Paul A. Smith
Controller and senior vice-president, finance and administration
Imperial Oil Limited
Calgary, Alberta

Jack M. Mintz
President and chief executive officer
C.D. Howe Institute
Toronto, Ontario

Randy L. Broiles
Senior vice-president, resources division
Imperial Oil Limited
Calgary, Alberta

Victor L. Young
Corporate director of several corporations
St. John's, Newfoundland and Labrador

Jim F. Shepard
Retired chairman and chief executive officer
Finning International Inc.
Vancouver,
British Columbia

(Seated, from left to right)

Roger Phillips
Retired president and chief executive officer
IPSCO Inc.
Regina, Saskatchewan

Tim J. Hearn
Chairman, president and chief executive officer
Imperial Oil Limited
Calgary, Alberta

Sheelagh D. Whittaker
Retired managing director
Electronic Data Systems Limited
London, England

Other officers

John F. Kyle
Vice-president and treasurer

Brian W. Livingston
Vice-president, general counsel and corporate secretary

Committees

Audit committee

J.F. Shepard, *chair*
S.D. Whittaker, *vice-chair*
J.M. Mintz
R. Phillips
V.L. Young

Environment, health and safety committee

S.D. Whittaker, *chair*
J.M. Mintz, *vice-chair*
V.L. Young
R. Phillips
J.F. Shepard

Executive resources committee

R. Phillips, *chair*
V.L. Young, *vice-chair*
J.M. Mintz
J.F. Shepard
S.D. Whittaker

Nominations and corporate governance committee

V.L. Young, *chair*
J.F. Shepard, *vice-chair*
J.M. Mintz
R. Phillips
S.D. Whittaker

Imperial Oil Foundation

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Imperial Oil

Imperial Oil Limited
P.O. Box 2480, Station 'M'
Calgary, Alberta
Canada T2P 3M9

www.imperialoil.ca

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