Esso Imperial Oil

ANNUAL REPORT 2008

ENERGY IS ESSENTIAL

Economic growth and energy use are tightly linked, with energy essential for economic progress. Oil and gas products make it possible for millions of Canadians to light and heat their homes, fuel their vehicles, and power their businesses.

Over the long term, we expect that:

Oil and natural gas will remain the world's primary energy sources

Even with an accelerated pace of advancement in energy efficiency, global demand for energy will reach the equivalent of about 310 million barrels of oil a day by 2030, or about 35 percent more than in 2005. This means that we must produce more energy from all available and commercially viable resources. There will be an increase in the use of alternative energy sources.

Due to their availability, affordability and versatility, hydrocarbons – oil, natural gas and coal – will continue to supply about 80 percent of the world's energy needs. Oil and natural gas alone will account for about 60 percent over the outlook period.

Resources will exist to meet demand

While oil and natural gas resources are abundant, supplying increasing amounts of these energy sources is a long-term proposition that will require massive investment, access to resources, environmental management and efficient energy markets. Open energy markets and expanding energy trade will be essential as global energy interdependence grows. Technological advances will also be vital to the world's energy future – increasing supply by tapping unconventional and frontier energy sources, mitigating demand growth by improving energy efficiency, and reducing the environmental impacts of increased energy production and use.

60%

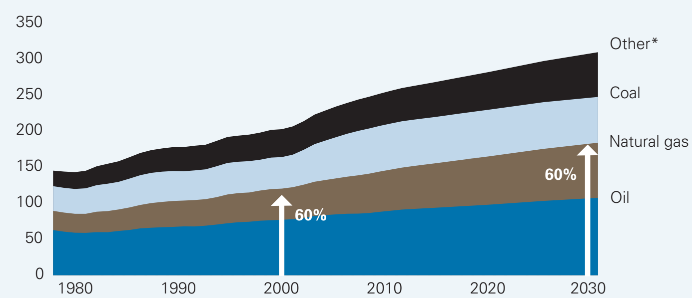
of the world's energy needs will continue to be supplied by oil and natural gas

Energy demand will increase even with the current economic downturn

Increasing population, long-term economic growth and improving living standards around the world will generate greater demand for all forms of energy. While growth in energy use will continue in North America, it will be strongest in developing countries such as China and India.

World energy demand is projected to grow at 1.2 percent a year

by fuel type – millions of oil-equivalent barrels a day



*Other energy sources include nuclear, hydro, biomass, wind and solar.

Contents

Forward-looking statements

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 Imperial Oil advantage

Imperial Oil is one of Canada's largest corporations and a leading member of the country's petroleum industry. It is one of the country's largest producers of crude oil and natural gas, and is the largest petroleum refiner and marketer with a coast-to-coast supply network that includes about 1,900 retail service stations.

We adhere to a proven, consistent strategy focused on long-term growth in shareholder value based on four corporate priorities:

- target flawless execution in everything we do
- grow profitable sales volumes
- attain best-in-class cost structures in each business
- improve the productivity of our asset mix

We are developing one of Canada's leading resource positions

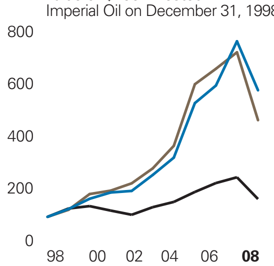
We are developing new technologies to improve existing operations, unlock energy resources, reduce environmental impacts and improve our products

We continually improve base operations to enhance safety, environmental performance, reliability and efficiency throughout the company

We create shareholder value – generating superior long-term investment returns

Sustained increase in shareholder value

value of $100 invested in Imperial Oil on December 31, 1998

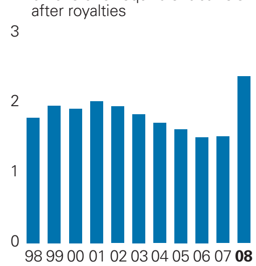


- Imperial Oil
- S&P/TSX Equity Energy Index[(1)]
- S&P/TSX Composite

Source: Bloomberg

Proved reserves*

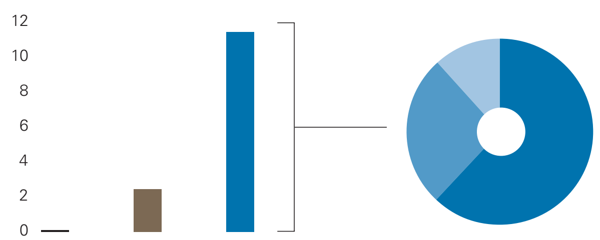
billions of oil-equivalent barrels after royalties



Significant resource base

Non-proved resources

billions of oil-equivalent barrels – 2008



- Net production
- Proved reserves*
- Non-proved resources**

- Mineable oil sands
- In-situ heavy oil
- Conventional, including frontier

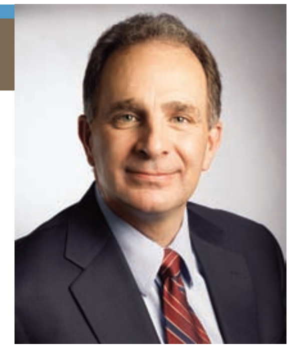
(1) From 2002 to 2004, the S&P/TSX Composite Energy Index was used. Prior to 2002, the S&P/TSX Energy Index was used.

* Based upon prices the company uses to make investment decisions – this basis is used for reporting reserves on pages 1-19 in this document unless otherwise noted. See page 62 for estimates based upon the U.S. Securities and Exchange Commission's requirement that applies December 31st prices and costs.

** Pursuant to National Instrument 51-101 disclosure guidelines, and using Canadian Oil and Gas Evaluation Handbook definitions, Imperial's non-proved resources are classified as a "contingent resource." Such resources are a best estimate of the company's net interest after royalties at year-end 2008, as determined by Imperial's internal qualified reserves evaluator. Contingent resources are considered to be potentially recoverable from known accumulations using established technology or technology under development, but are currently not considered to be commercially recoverable due to one or more contingencies. There is no certainty that it will be economically viable or technically feasible to produce any portion of the resource. See discussion on pages 8-13 in the Upstream section for additional information on components of the contingent resource base, including undeveloped oil sands acreage and the Mackenzie natural gas project.

- Significant resource base of nearly 14 billion oil-equivalent barrels.
- Non-proved resources of more than 11 billion oil-equivalent barrels, of which 10 billion barrels are heavy oil and oil sands.
- Long-life reserves.

CHAIRMAN'S LETTER



Imperial is well positioned to grow in today's challenging times.

It's hard to imagine a more volatile year than the one experienced in 2008 – industries and economies the world over were impacted by the year's events. But despite these challenging economic times, Imperial Oil continued to position itself for long-term growth while producing solid results for shareholders in 2008:

- net income was $3.9 billion, the highest in our history
- regular annual per-share dividends were increased for the 14th consecutive year
- $2.5 billion was distributed to shareholders through dividend payments and share repurchases

The basis for our continued prosperity comes from a long-standing focus on the factors we can control in our business. Our business model enables us to excel when market conditions are favourable and to prosper during difficult times through:

- prudent financial management and business controls
- disciplined capital investment
- operational excellence

Going forward, financial strength is essential. Our balance sheet is built on an efficient and conservative approach, and we have essentially no debt. The company's investment discipline includes developing projects to ensure their returns will be resilient over a wide range of economic scenarios. This has laid the foundation for a portfolio of projects that will continue to move forward in the current economic environment and will double our company's size in the years to come.

In the area of operational excellence, we continue to focus on improving safety, environmental performance, reliability and efficiency across the business. In 2008, we sustained industry-leading employee safety performance. We are proud of the progress made in 2008 to improve our operations reliability, with more improvements to come in making our assets more reliable and more efficient.

We also continued to look for opportunities to grow our business.

The Kearl oil sands project represents a tremendous opportunity, and we are committed to developing it responsibly. Advanced technology, operational excellence, and ongoing consultation with stakeholders will contribute to reducing impacts on the environment while optimizing the social and economic benefits.

At the Cold Lake heavy oil operation, we outlined growth plans that will add another 30,000 barrels a day of production. In addition, our ongoing commitment to research saw us advance the use of a technology that enhances resource recovery at Cold Lake by adding a small amount of solvent into the steaming process. At Syncrude, we are working to increase production and reduce costs at the world's largest producer of synthetic crude oil from oil sands.

Natural gas opportunities continued to be advanced as well. In the Horn River Basin of British Columbia, exploration drilling and evaluation are underway and we increased our land position in this promising unconventional natural gas area. In the Mackenzie Delta area of the Northwest Territories, the regulatory approvals process continues on a project that would create the infrastructure to bring an estimated six trillion cubic feet of onshore natural gas resource to North America. The Taglu field (100-percent Imperial) contains three trillion cubic feet of this resource.

Aside from oil sands and gas-related projects, we continued to explore for world-class discoveries in frontier areas. In the Beaufort Sea, we completed a 3-D seismic survey that will help us position a future exploration well. And off the east coast of Newfoundland, we're working with our partners to develop plans for a second exploration well to test the oil and gas potential of the Orphan Basin.

Complementing the Upstream's growth potential is the strength of integration with our Downstream assets.

In the Downstream and Chemical businesses, upgrades at our manufacturing and retail sites further improved productivity, efficiency and flexibility. Such investments are increasing our capacity to convert crude oil into higher-value products, strengthening our position in a highly competitive retail market and enabling us to respond efficiently and profitably to shifting customer demands.

All of these initiatives will position us for success in 2009 and beyond.

Continued economic uncertainty will affect market conditions and demand for our products in the year ahead. Our disciplined, prudent approach and unparalleled financial strength will enable us to take advantage of a period of decreasing costs and improving labour productivity as we invest in our future. In 2009, our capital and exploration program will increase to $2.2 billion.

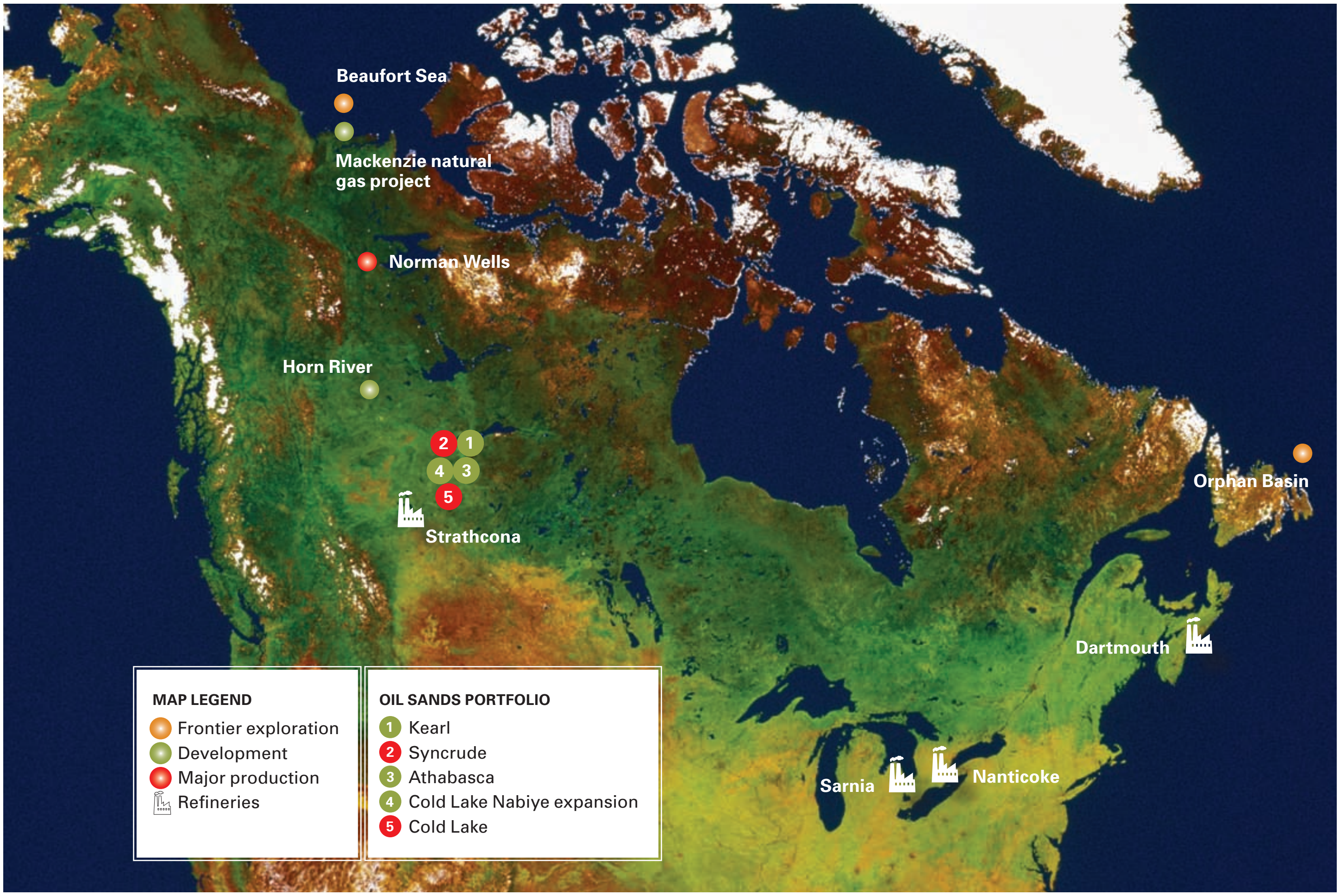
Our dedicated workforce is following proven strategies, and our strong commitment to research and technology is helping us unlock future energy resources while reducing environmental impacts.

With these strengths and our proven record of performance, I believe shareholders can look forward to continued success at Imperial – a company solidly positioned to grow.

B.H. March

Bruce March

Chairman, president and chief executive officer
February 24, 2009



UNLOCKING CANADA'S RESOURCE POTENTIAL WITH A PROVEN, INTEGRATED APPROACH

As an integrated energy company, we explore for, produce, refine and market products that are essential to society. Each of our businesses is distinct, but all are complementary and managed by the same principles.

EXPLORATION

Unlocking Canada's resource potential in frontier areas with ingenuity, major investment, Arctic capability and leading-edge technology.

DEVELOPMENT AND PRODUCTION

Developing discovered resources using world-class technology, global project management techniques and financial strength.

Producing crude oil and natural gas in an economically and environmentally responsible way, with a commitment to world-class research and advanced technology.

MARKETING

Delivering petroleum products across Canada through secure and ratable outlets of more than 100 distribution terminals and about 1,900 retail service stations.

REFINING AND PETROCHEMICALS

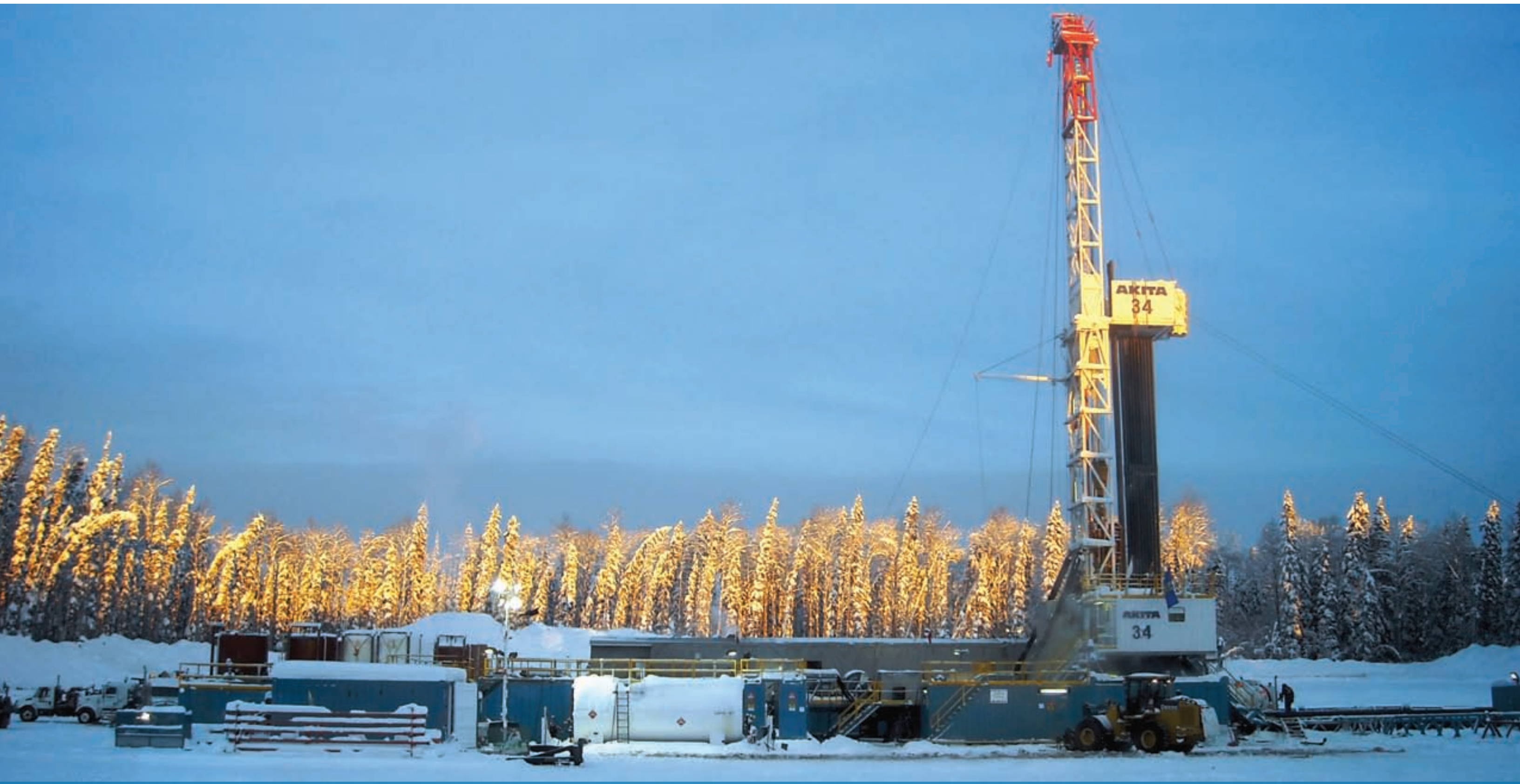
Refining crude oil into petroleum products with a proven model of continuous operations improvement and delivering cost efficiencies. Chemical and lubricants manufacturing assets are fully integrated with refineries, maximizing value through optimized operations.

2008 Year in review

OPERATING HIGHLIGHTS

Safety and environment

- Sustained industry-leading employee safety performance. Initiatives to improve contractor safety continued in all parts of our operations, toward the goal of "Nobody Gets Hurt."
- Environmental management and performance remained a major focus. About 130 managers and supervisors were trained in environmental leadership to support our focus: "Protect Tomorrow. Today."
- More than 95 percent of produced water is treated and recycled for steam production at Imperial's Cold Lake production facility. At Syncrude, where Imperial is a 25-percent owner, about 88 percent of all water used comes from a continuous recycle loop.
- Committed more than $100 million to reduce sulphur dioxide (SO_2) emissions at Sarnia and Dartmouth refineries:
  - Started construction on a new unit at Sarnia, that when coupled with operational enhancements, will enable the site to reduce SO_2 emissions by more than 50 percent.
  - At Dartmouth, a project was commenced that will enable SO_2 emissions to be reduced by more than 25 percent.
- Completed the first full year of operation of a sulphur recovery unit that will reduce SO_2 emissions from Cold Lake's Mahihkan plant by more than 70 percent, and started up a new sulphur recovery unit at the Mahkeses plant that will reduce SO_2 emissions by more than 70 percent.



Imperial has an extensive land position in the Horn River Basin, a promising unconventional shale gas area in northern British Columbia. Exploration drilling commenced in 2008.

Advanced major projects and new opportunities

- About 800 million barrels were added to Imperial's proved reserves in connection with phase one of the Kearl oil sands project.
- Commenced exploration drilling and evaluation in the Horn River Basin of northeast British Columbia.
- Completed an extensive 3-D seismic survey in the Beaufort Sea.
- Progressed planning and design work on the Nabiye project, the next phase of expansion at the Cold Lake heavy oil operation.
- Piloted a technology involving continuous steam flooding to improve resource recovery in mature portions of the field at Cold Lake.
- Advanced the use of a technology that improves resource recovery at existing Cold Lake wells by adding solvent to the steaming process.
- Commenced a pilot program that adds solvent to Steam-Assisted Gravity Drainage (SAGD) wells. The technology has potential to enhance recovery for certain reservoirs in the Cold Lake and Athabasca areas.

Reserves growth and volume performance

- Increased proved reserves after royalties from 1.5 billion oil-equivalent barrels at year-end 2007 to about 2.4 billion oil-equivalent barrels at year-end 2008.
- Daily production of crude oil, natural gas and natural gas liquids averaged 308,000 oil-equivalent barrels a day before royalties.
- Net petroleum product sales volumes averaged 438,000 barrels a day; Imperial is the largest petroleum refiner in Canada.

Corporate citizenship

- We continued our long tradition of contributing to the communities where we operate by creating jobs, providing products that Canadians need and investing in community initiatives. Imperial's funding totaled $12.1 million in 2008.
- We hired more than 100 new university graduates.
- See our corporate citizenship report at www.imperialoil.ca.

Research and development

- Total research expenditures in Canada were $117 million in 2008. In addition, through its relationship with ExxonMobil, Imperial had access to about $900 million of industry-leading research worldwide.
- In 2008, the Imperial Oil-Alberta Ingenuity Centre for Oil Sands Innovation (COSI) research portfolio comprised three key program areas aimed at the sustainable development of Alberta's oil sands and improved environmental performance. For example, the five integrated projects in the non-aqueous extraction program are developing the fundamental science base that could lead to a bitumen extraction process with up to a 60-percent reduction in fresh water use, the elimination of tailings ponds and a reduction in GHG intensity.

About
$500 million
invested in Kearl to date

2008 Year in review

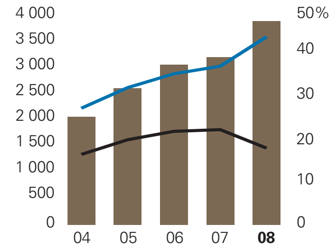
FINANCIAL HIGHLIGHTS

- Achieved record earnings of $3.9 billion or $4.36 per share.
- Achieved an industry-leading return on capital employed of 45 percent.
- Annual per-share dividends paid increased for the 14th year in a row. Imperial has paid a dividend to shareholders every year since 1890.
- Shareholder distributions totaled $2.5 billion through dividend payments and share repurchases.
- Sustained a strong balance sheet with $2 billion in cash and essentially no debt. Debt as a percentage of total capital was at two percent at year-end, interest coverage was 661 times on an earnings basis, and 721 times on a cash flow basis.
- Maintained a "AAA" rating from Standard & Poor's, the only Canadian industrial company with this rating.
- Completed a $1.4 billion capital and exploration program.
- Planned capital and exploration expenditures in 2009 of $2.2 billion, to be financed entirely through internally generated funds.

$3.9 billion
in net income, return on capital employed of 45%

Net income
millions of dollars

Return on capital employed (ROCE)
percent



- Imperial Oil ROCE (percent)
- Canadian integrated oil companies ROCE (percent)
- Net income

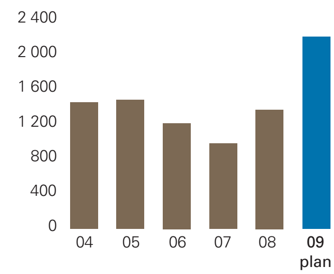
Source: Bloomberg and quarterly reports

Financial highlights

millions of dollars	2008	2007	2006	2005	2004
Operating revenues (a)	**31 240**	25 069	24 505	27 797	22 408
Net income	**3 878**	3 188	3 044	2 600	2 052
Cash flow from operating activities and asset sales (b)	**4 535**	3 905	3 799	3 891	3 414
Cash and cash equivalents at year-end	**1 974**	1 208	2 158	1 661	1 279
Total debt at year-end	**143**	146	1 437	1 439	1 443
Average capital employed (c)	**8 684**	8 509	8 515	7 976	7 425

(a) Operating revenues include $4,894 million for 2005 and $3,584 million for 2004 for purchases/sales contracts with the same counterparty. Associated costs were included in purchases of crude oil and products. Effective January 1, 2006, these purchases/sales were recorded on a net basis.
(b) A definition of cash flow from operating activities and asset sales can be found on page 35.
(c) A definition of average capital employed can be found on page 34.

Capital and exploration expenditures
millions of dollars



Key financial ratios

	2008	2007	2006	2005	2004
Net income per share – diluted (dollars) (a)	**4.36**	3.41	3.11	2.53	1.91
Return on average capital employed (percent) (b)	**44.7**	37.7	35.9	32.6	27.7
Return on average shareholders' equity (percent) (c)	**45.7**	41.6	43.5	40.2	34.6
Annual shareholders' return (percent) (d)	**(24.3)**	28.0	12.5	64.0	25.3
Debt to capital (percent) (e)	**2**	2	17	18	19

(a) Calculated by reference to the average number of shares outstanding, weighted monthly (page 64).
(b) A definition of return on average capital employed can be found on page 35.
(c) Net income divided by average shareholders' equity (page 39).
(d) Includes share appreciation and dividends.
(e) Current and long-term portions of debt (page 39) and the company's share of equity company debt, divided by debt and shareholders' equity (page 39).

DEVELOPING CANADA'S OIL SANDS RESPONSIBLY

Satisfying the world's demand for energy will require both renewable and non-renewable sources. Because of their size, the oil sands of northern Alberta – second only in size to Saudi Arabia for estimated recoverable oil – will play an increasingly important role in the global supply picture. The development of the oil sands is creating employment and economic benefits for Canadians, but with this opportunity comes the requirement to reduce the impacts on the environment. Imperial's own research organization made investments of $80 million in 2008 to advance opportunities to lessen impacts on the air, water and land affected by oil sands production.

Greenhouse gas emissions

Significantly reducing global CO_2 emissions growth is a challenging proposition that will require global participation, step changes in energy efficiency, significant technology gains, and massive investment over decades.

The oil sands industry currently accounts for about four percent of Canada's total greenhouse gas (GHG) emissions – or about 0.1 percent of global emissions.

GHG emissions can be reduced by improving energy efficiency. For example, at Syncrude, improvements have reduced energy intensity per barrel by nearly 20 percent since 2006. Longer term, breakthrough technologies will be required to make a step change. To this end, Imperial is a founding partner of the Imperial Oil-Alberta Ingenuity Centre for Oil Sands Innovation (COSI) at the University of Alberta. This centre brings together some of the best scientific and engineering minds to seek new technologies associated with oil sands development, including more energy-efficient ways to extract and upgrade the resource.

In addition, at Imperial's own Calgary research facility, we are working on solvent-based heavy oil recovery processes that can significantly reduce GHG emissions compared to current thermal recovery processes. Imperial is also an active member of the Integrated CO_2 Network, a consortium of companies exploring the viability of developing a large scale Canadian carbon dioxide capture, transportation and storage network. Carbon capture and storage has been identified as a potential method of reducing future GHG emissions from the oil sands.

Water

Extracting bitumen from oil sands uses water, and we are steadily reducing the quantity required through extraction efficiency. Through more than 40 years of technical innovation, Imperial has pioneered state-of-the-art water recycling technology at Cold Lake. Today the operation recycles more than 95 percent of the water that is recovered with the bitumen, helping to reduce requirements for fresh water.

Looking ahead, promising research at COSI is underway to develop a non-aqueous extraction process for oil sands mining that could significantly reduce fresh water use.

Another outcome of this research could also lead to the production of dry or "stackable" tailings, which would eliminate the need for large tailings ponds.

Land

Surface mining of the oil sands has the most visible impact on the land. Only about 20 percent of Alberta's oil sands resource is suitable for surface mining. To put this into context, Canada's boreal forest encompasses 3,200,000 square kilometres, of which 420 square kilometres is currently being disturbed through surface mining. This represents 0.01 percent of the Canadian boreal forest.

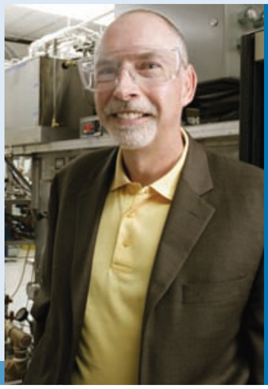
While 20 percent of the oil sands can be surface mined, the other 80 percent requires in-situ technologies to bring the oil to the surface. Our Cold Lake operation, the largest thermal in-situ operation in the world, uses this technology in centrally located well clusters, resulting in a smaller surface disturbance. And, of the total land area that has been disturbed, about 19 percent has been permanently reclaimed.

19%
of land reclaimed at Cold Lake

We are working to further reduce our temporary footprint through each phase of operation. For example, at ongoing operations like Syncrude, 22 percent of disturbed land has been reclaimed – and Syncrude in 2008 received the industry's first provincial land reclamation certificate for a 104-hectare parcel known as Gateway Hill.

Ultimately, all oil sands operations are required to reclaim the land they disturb. Imperial, together with other oil sands operators, is funding leading-edge reclamation research conducted by the Canadian Oil Sands Network for Research and Development.

Industry, governments and the research community all have roles to play in ensuring the responsible development of Canada's oil sands. It is a shared obligation that will call for the development and integration of new ideas and technologies – and action.



Ron Myers, manager of Imperial's facilities and environment research group, leads a multi-disciplinary research team that is developing more energy efficient oil sands processes that have a reduced environmental footprint.

Upstream

Imperial completed a 3-D seismic survey in the Beaufort Sea, a promising frontier exploration area. This work was conducted on the large acreage position acquired in 2007. Imperial has a strong offshore position in the Mackenzie Delta and Beaufort region.

We are advancing a high-quality portfolio of major projects that position the company for significant long-term volume growth.

Our Upstream business continued its record of superior operating performance in 2008, generating earnings of $2,923 million, cash flow from operating activities and asset sales of $3,712 million and return on average capital employed of 65 percent.

We produced an average of 308,000 oil-equivalent barrels a day before royalties of heavy oil, synthetic crude oil, natural gas, and conventional crude oil and natural gas liquids.

Capital and exploration spending totaled $1.1 billion in 2008 with about $1.8 billion planned in 2009, largely for future reserve additions and production growth.

The resource base

Our total proved and non-proved resource base is about 14 billion oil-equivalent barrels after royalties, representing about 150 years of production at current levels – a leading position in terms of size and quality. The resource base comprises about 2.4 billion oil-equivalent barrels of proved reserves – a 56-percent increase over last year – and more than 11 billion oil-equivalent barrels of non-proved resources, which consist primarily of heavy oil and oil sands.

Phase one of Kearl added about

800

million barrels to proved reserves

Looking ahead, we are advancing an inventory of major projects to add reserves and production. These include:

- future mining phases of Syncrude and Kearl
- in-situ development at Cold Lake and in the Athabasca area
- unconventional gas in northeast British Columbia
- natural gas and liquids from the onshore Mackenzie Delta region and Canada's High Arctic
- hydrocarbons from the Beaufort Sea and the Orphan Basin off Canada's East Coast

AT A GLANCE

	2008	2007	2006	2005	2004
Net income (millions of dollars)	**2 923**	2 369	2 376	2 008	1 517
Cash flow from operating activities and asset sales (millions of dollars)	**3 712**	2 661	3 151	2 805	2 395
Gross crude oil and NGL production (thousands of barrels a day)	**256**	275	272	261	262
Gross natural gas production (millions of cubic feet a day)	**310**	458	556	580	569
Average capital employed (millions of dollars)	**4 526**	4 258	3 993	3 928	3 877
Return on average capital employed (percent)	**64.6**	55.6	59.5	51.1	39.1

Heavy oil and oil sands

Canada's oil sands are an increasingly important energy source in helping to meet the world's long-term energy needs and sustaining Canadian economic prosperity. The oil sands represent a national opportunity, but there are challenges with respect to bringing the resource to market efficiently and in an environmentally responsible manner. As an oil sands pioneer, we are using our technological and operational expertise to overcome these challenges.

Cold Lake

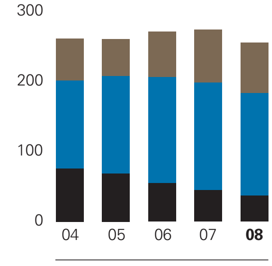
Cold Lake is the world's largest thermal in-situ heavy oil operation, representing more than four percent of Canada's total oil production. Proved reserves are about 672 million barrels after royalties, representing production for another 15 years at current rates. Cold Lake's non-proved resources are about 2 billion barrels.

Production in 2008 averaged 147,000 barrels a day before royalties – down from the record 154,000 barrels a day in 2007. Lower production volumes were due to the cyclic nature of production.

Ongoing research and application of technologies to improve recovery have been mainstays of Cold Lake's success. More than $250 million was spent on such initiatives prior to the project's commercial start-up in 1985. Since that time, resource recovery rates have nearly doubled, to about 30 percent today. This technology evolution continued in 2008, as we piloted a new technology that uses continuous steam flooding to enhance recovery in mature portions of the reservoir, and we progressed the use of Liquid Addition to Steam for Enhanced Recovery – a technology that enhances recovery by adding solvent to the steaming process.

Crude oil and NGL production by source

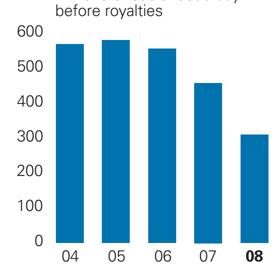
thousands of barrels a day before royalties



Oil sands production from Syncrude and Cold Lake provides a strong production base to replace declining conventional volumes.

Natural gas production

millions of cubic feet a day before royalties

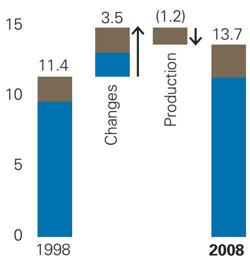


Natural gas declines occurred as expected in 2008, following completion of the Wizard Lake blowdown.

Production at the Cold Lake heavy oil operation averaged 147,000 barrels a day before royalties in 2008. The site has more than 4,500 wells drilled from some 200 multi-well pads, four plants that generate steam and process bitumen, and a cogeneration unit. Pictured here are employees Vince Burke and Donna Pinder.

Resource base

billions of oil-equivalent barrels after royalties



● Proved reserves
● Non-proved resources

Proved reserves replacement of 150 percent and resource replacement of 300 percent over the last decade.

In addition to Imperial's sustained investments in technology to enhance recovery, the regulator-approved Nabiye project will add new producing well pads, a processing plant and about 30,000 barrels a day of production.

This development builds on the merits of continued technology improvements made possible by a phased development approach. Three modifications from the current approval are being considered to further improve environmental performance: a modified field development plan to reduce surface footprint, addition of a cogeneration facility to improve energy efficiency, and addition of sulphur-removal facilities to reduce sulphur-dioxide emissions.

Syncrude

Imperial holds a 25-percent interest in Syncrude, an integrated mining, extraction and upgrading facility located north of Fort McMurray, Alberta. Syncrude has proved reserves of 2.9 billion barrels of synthetic crude oil after royalties, translating into about 32 years of production at current rates. Syncrude's non-proved resources are more than 9 billion barrels of synthetic crude oil.

Imperial's share of production averaged 72,000 barrels a day before royalties – down from 76,000 barrels a day in 2007. Lower volumes were primarily the result of increased mining and plant maintenance activities during the year.

Production from Syncrude represents about nine percent of Canadian oil production, and offers strong opportunity for future growth.

A multi-year plan to improve operating performance continued in 2008, with a focus on improved reliability. Such improvements in 2008 included greater energy efficiency, higher synthetic crude oil yield from bitumen, and strong planned maintenance turnaround performance.

On behalf of the Syncrude owners and under the provisions of the 2007 Management Services Agreement, ExxonMobil and Imperial assumed responsibility for operations oversight and major project development. Progress to date includes improved safety performance and lower energy intensity through reduced flaring and enhanced energy management. As well, there have been improvements in plant reliability and major turnaround execution with the implementation of ExxonMobil Global Best Practices.

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 (Syncrude) millions of barrels		Mined bitumen (Kearl) millions of barrels	
	Conventional		Heavy Oil (Cold Lake)		Total							
year ended	gross	net	gross	net	gross	net	gross	net	gross	net	gross	net
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	–	–
2006 (b)	81	65	667	616	748	681	830	673	792	718	–	–
2007 (b)	96	76	727	649	823	725	779	622	765	694	–	–
2008 (b)	**88**	**67**	**753**	**672**	**841**	**739**	**743**	**603**	**809**	**734**	**962**	**807**

(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) Based upon prices the company uses to make investment decisions; see page 62 for estimates based upon the U.S. Securities and Exchange Commission's requirement that applies December 31st prices and costs.

Conventional production

Imperial remains a large domestic producer of conventional crude oil and natural gas. Production before royalties averaged about 37,000 barrels a day of crude oil and natural gas liquids, and about 310 million cubic feet a day of natural gas, for a combined total of approximately 89,000 oil-equivalent barrels a day.

Western Canada
Conventional production in Western Canada is at a mature stage. To help ensure profitability, Imperial focuses on cost control, maximizing production of existing assets, and pursuing all projects with the potential for attractive returns. In 2008, these included new drilling at Norman Wells and the ongoing shallow gas drilling program in southeastern Alberta.

FUTURE GROWTH OPPORTUNITIES

Undeveloped acreage
Adding to the high-quality oil sands assets of Cold Lake, Syncrude and Kearl, Imperial holds extensive undeveloped acreage with promising mining and in-situ development opportunities in the Athabasca region of Alberta. The Athabasca delineation program will continue in 2009, targeting further resource additions.

Horn River

Imperial (50-percent interest) and ExxonMobil Canada have acquired more than 152,000 net acres in British Columbia's Horn River Basin, a frontier exploration area where natural gas is trapped in shale rock. Although challenging to produce, unconventional resources such as shale gas can be prolific – and preliminary industry results in the area have been promising. The viability of shale gas as a large-scale energy source has been made possible by technologies that better fracture rocks in extended-reach horizontal wells, enabling the resource to be accessed in an economic manner.

Our exploration drilling and evaluation of the Horn River acreage commenced in 2008 with a four-well program, and with success as well as additional exploration activities, Horn River could be another large, long-life natural gas project that advances with a disciplined development approach.

Mackenzie natural gas project

The Mackenzie Delta represents an important potential source of energy for North America.

Located in Canada's north, the proposed Mackenzie natural gas project would create the infrastructure to bring an estimated six trillion cubic feet of onshore natural gas resource to North American markets from three fields, with the Taglu field (100-percent Imperial) containing resources of three trillion cubic feet alone. The project would be built with sufficient capacity to accommodate future discoveries along the pipeline route.

After several years of work on the project, the regulatory approvals process has not yet concluded. Project spending has been minimized, and current activities are focused on finalizing remaining benefits and access agreements as well as establishing an appropriate fiscal framework with the federal government.

Timing for a regulatory decision is dependent on the issuance of a report by the Joint Review Panel.

Offshore exploration

Our search for world-class oil and gas discoveries takes us to some of Canada's most remote and technically challenging regions, where we use our demonstrated expertise and leading-edge technology to unlock resource potential.

Beaufort Sea
The Beaufort Sea is a frontier area of exploration in Canada's Arctic. A multi-year exploration licence covering more than 500,000 acres was acquired by Imperial (50-percent interest) and ExxonMobil Canada in 2007, adding to an already strong offshore position in the Mackenzie Delta and Beaufort region. The exploration area is located about 120 km north of the Taglu field in the Northwest Territories, in varying water depths.

In 2008, a 3-D seismic program was completed that utilized the services of professional wildlife biologists and traditional-knowledge experts hired from local Aboriginal communities. Results from this program will help us evaluate the resource potential and future exploration drilling in this promising area.

Orphan Basin
The Orphan Basin is located in the Atlantic Ocean, about 400 km northeast of St. John's, Newfoundland. Imperial has a 15-percent interest in a position that spans 4.2 million acres. Exploration in this remote area is technically challenging and high cost, but has potential for containing large amounts of hydrocarbons. The drilling of the first exploration well, one of the deepest in Canadian history, was completed by co-venturers in 2007. We have integrated lessons from this well into plans for the drilling of the next exploration well.

KEARL: A WORLD-CLASS RESOURCE

Kearl is a long-life, high-quality oil sands mining opportunity located north of Fort McMurray, Alberta. The proposed three-phase project has an estimated total recoverable resource of 4.6 billion barrels of bitumen before royalties – in which Imperial holds about a 70-percent interest.

In connection with the first phase of development, about 800 million barrels of bitumen after royalties were added to Imperial's proved reserves in 2008, marking a major project milestone.

Kearl represents one of the best undeveloped resources in terms of the quantity of bitumen that can be produced for a given volume of mined material, providing the project with an inherent cost advantage. Kearl will utilize proven technologies such as truck-and-shovel mining and hydrotransport, as well as newer ones, such as high-temperature paraffinic froth treatment – a technology developed by the company that produces a higher-quality, marketable bitumen product.

Based on our proven success at Cold Lake, the Kearl project will advance in phases, enabling new technologies, improved management processes, and advanced operational know-how to be applied as they emerge.

The first phase of Kearl has the potential to initially produce 110,000 barrels of bitumen a day before royalties, of which Imperial's share would be about 78,000 barrels a day.

The project has an estimated lifespan of about 40 years, and when all three phases are completed, it could produce more than 300,000 barrels of bitumen a day before royalties.

In 2008, activities focused on engineering, access road construction, site preparation and earthworks. By year-end, about $500 million had been invested in Kearl, and there are currently nearly 1,200 employees and contractors working on project development.

Detailed design engineering continues and procurement of items that require long lead times has started. Current activities also include reducing the overall project cost by capturing productivity improvements and finalizing transportation system agreements. Safety, disciplined execution of project plans, and cost reduction remain strongly in focus as the project advances.

Stuart Nadeau is the environmental and regulatory manager for Kearl, an oil sands mining project with the potential to produce more than 300,000 barrels a day. Imperial is committed to developing Kearl responsibly – with advanced technology, operational excellence, and ongoing consultation with stakeholders.

Downstream

Our refinery in Sarnia, Ontario can process 121,000 barrels of crude oil a day into a range of petroleum products for heat, light, transportation and lubrication. The chemical plant produces the raw materials for a variety of industrial and consumer products such as containers and recreational goods.

With the capacity to process 500,000 barrels of crude oil a day, we are the largest refiner and marketer of petroleum products in Canada.

Our Downstream operations convert crude oil into more than 700 petroleum products that consumers and businesses need and use every day.

We continue to have a leading market share in petroleum product sales, including retail fuels and finished lubricants. Our competitive advantage is achieved by having refining and marketing operations in Western, Central and Atlantic Canada.

Net earnings from the Downstream totaled $796 million, down from a record $921 million in 2007.

Earnings decreased primarily due to lower overall downstream margins, higher planned maintenance costs and lower sales volumes. These factors were partially offset by a gain of $187 million from the sale of the company's equity investment in Rainbow Pipe Line Co. Ltd.

Return on average capital employed was 23 percent, and cash flow from operating activities and asset sales totaled $539 million.

Total refinery throughput was 446,000 barrels a day, up from 2007, and average refinery utilization was 89 percent. Production gains from reliability improvements through the year were partially offset by the impact of declining economic conditions that did not support running the refineries to full capacity.

Total net petroleum product sales were 438,000 barrels a day, down slightly from 2007.

Capital investment in the Downstream totaled $232 million in 2008, and was focused on improving air emissions, increasing refinery capacity utilization and upgrading the retail network.

AT A GLANCE

	2008	2007	2006	2005	2004
Net income (millions of dollars)	**796**	921	624	694	556
Cash flow from operating activities and asset sales (millions of dollars)	**539**	1 180	562	874	946
Refinery throughput (thousands of barrels a day)	**446**	442	442	466	467
Refinery utilization (percent)	**89**	88	88	93	93
Net petroleum product sales (thousands of barrels a day)*	**438**	448	453	465	462
Average capital employed (millions of dollars)	**3 460**	3 257	3 161	2 906	2 831
Return on average capital employed (percent)	**23.0**	28.3	19.7	23.9	19.6

*Net petroleum product sales do not include sales under purchases/sales contracts with the same counterparty.

MARKET RESPONSIVENESS IN THE DOWNSTREAM

Investing to meet customers' changing needs

Petroleum refining is capital intensive, cyclical and competitive. Manufacturing processes are complex, and long lead times can be required when making significant changes to the mix of petroleum products produced. In such an environment, the speed at which refineries respond to market conditions and customers' evolving energy needs leads to a competitive advantage and increased profitability.

In 2008, in response to market conditions that favoured diesel production over gasoline, Imperial made refinery investments in new hardware and modified operations to optimize diesel production. As well, the crude slate was expanded to include crudes that are difficult to process but offer a higher refining incentive. As a result of these improvements, we increased our diesel production, enabling Imperial to capture the highest value for its products.

We continue to expand the number of company-owned retail sites that offer diesel to meet the growing demand for this profitable fuel.

There are about 1,900 Esso-branded service stations serving customers across Canada. The network continued to be upgraded in 2008.

Offering customers high-quality choices

In the fuels marketing side of the business, our brands are evolving with the changing needs and expectations of the marketplace. Investments are being made to upgrade and modernize the retail chain. The chain serves customers through about 1,900 Esso-branded retail service stations, which include about 370 On the Run-branded stores that consistently deliver convenience, quality and value. Products and services continue to be added, and alliances with Tim Hortons, Royal Bank and Aeroplan further enhance the convenience store offer. As well, we have the largest network of car washes in the country.

Imperial is the Canadian distributor for Mobil 1 synthetic lubricants. In 2008, we continued to expand the market presence with twelve Mobil 1 Lube Express franchise locations across five provinces.

Offering customers innovative products and services

Selling under the Esso and Mobil brands, we are the Canadian market-share leader for finished lubricants. This success is due in large part to a long history of providing innovative, high-quality products and services to customers.

Imperial is the Canadian distributor for Mobil 1 synthetic lubricants – products that provide customers with outstanding engine protection and improved gas mileage. In 2008, the product line was expanded with the launch of Mobil Super 1000 passenger vehicle engine oil, serving the new vehicle market, and Mobil Super 2000, serving the high-mileage vehicle market.

The entire product offering is complemented by a coast-to-coast network of technical specialists – recognized experts in their field who help customers select products best matched to their needs and save money in their operations.

Imperial is positioned to excel in a highly competitive market in the years ahead, introducing new and innovative products through access to world-scale research.

Alliances with Tim Hortons, Royal Bank and Aeroplan provide competitive advantage.

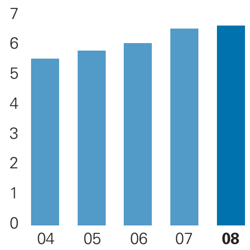
Customers can pay in a variety of ways at many locations, with pay-at-the-pump options for debit card, credit card and *Speedpass* transponder – the fastest and easiest way to pay.

Leading refiner and marketer of petroleum products in Canada

Productivity and competitiveness of the retail chain increased.

Annual throughput – company-owned or leased retail service stations

millions of litres per site



Site productivity has increased 20 percent since 2004.

Esso retail service stations

at year end

The retail chain upgrading program continued in 2008, with significant investment to enhance site offers and divestment of non-strategic sites. This program further increased the competitiveness of the chain.

In 2009, capital expenditures of about $400 million are planned. Refinery projects will focus on increasing sulphur recovery to further reduce sulphur dioxide emissions, upgrading water management systems, as well as enhancing feedstock flexibility and energy efficiency. Retail projects will continue to focus on network upgrades in major urban markets.

About $330 million has been invested to improve the company-owned retail chain over the past five years, making the business a pacesetter in site productivity, with the best locations and leading-edge site offers. The business maintained best-in-class unit cash costs, with site productivity reaching an average of 6.7 million litres – an increase of 20 percent since 2004 – and continued growth in convenience store sales.

In addition to serving retail customers, the fuels marketing and lubricants businesses supplied petroleum products to the mining, manufacturing, forestry, construction and transportation industries across Canada in 2008. Petroleum products are provided through a national network of 24 primary distribution terminals and 92 secondary bulk terminals. Imperial is the only company to operate lube oil manufacturing, blending and marketing facilities in both the east and west.

Janet Matsushita is the manager of our refinery in Dartmouth, Nova Scotia – one of four Imperial refineries. Dartmouth has a rated capacity of about 82,000 barrels of crude oil a day and produces a wide range of petroleum products including gasoline, diesel fuel, home heating fuel, asphalt and aviation fuel.

Chemical

John Stover of the Sarnia Polymers Technology Centre performs one of many tests that assist customers in designing new products that contain our resin.

Imperial is one of Canada's leading producers of chemical products, with the largest market share in North America for polyethylene used in rotational molding and the second-largest market share in injection molding.

Like the Downstream segment, the Chemical business operates in a competitive, cyclical and global marketplace. Margins in 2008 were above the historical average, but down from peaks seen in 2006.

To help ensure profitable operations throughout the entire business cycle, we continue to integrate petrochemical manufacturing with refinery operations. Integration enables feedstocks and production to be adjusted to current market conditions – and to reduce costs by sharing management, leveraging common site infrastructure and efficiently managing energy needs across the site.

A sustained emphasis on such initiatives helped keep the Chemical business a leader in cost and productivity in 2008.

Chemical net earnings in 2008 were $100 million, up from $97 million in 2007. Higher margins for polyethylene products were essentially offset by lower margins for intermediate products and lower sales volumes for both polyethylene and intermediate products.

Return on average capital employed was 50 percent, and cash flow from operating activities and asset sales totaled $183 million.

Leader in cost and productivity

Total sales of petrochemical products were about 2,800 tonnes a day, down from 2007, primarily due to decreased sales of polymers and intermediate products.

Capital expenditures of $13 million in 2008 were primarily focused on investments to upgrade water management systems, improve safety and increase feedstock flexibility.

Planned capital expenditures in 2009 are about $35 million, and will include continued investments to increase feedstock flexibility and further upgrade water management and safety systems.

AT A GLANCE

	2008	2007	2006	2005	2004
Net income (millions of dollars)	**100**	97	143	121	109
Cash flow from operating activities and asset sales (millions of dollars)	**183**	109	162	94	126
Chemical sales volumes (thousands of tonnes a day)	**2.8**	3.1	3.0	3.0	3.3
Average capital employed (millions of dollars)	**199**	230	261	272	261
Return on average capital employed (percent)	**50.4**	42.2	54.8	44.6	41.8

FINANCIAL SUMMARY (U.S. GAAP)

millions of dollars	2008	2007	2006	2005	2004
Operating revenues (a)	**31 240**	25 069	24 505	27 797	22 408
Net income by segment:					
Upstream	**2 923**	2 369	2 376	2 008	1 517
Downstream	**796**	921	624	694	556
Chemical	**100**	97	143	121	109
Corporate and other	**59**	(199)	(99)	(223)	(130)
Net income	**3 878**	3 188	3 044	2 600	2 052
Cash and cash equivalents at year end	**1 974**	1 208	2 158	1 661	1 279
Total assets at year end	**17 035**	16 287	16 141	15 582	14 027
Long-term debt at year end	**34**	38	359	863	367
Total debt at year end	**143**	146	1 437	1 439	1 443
Other long-term obligations at year end	**2 298**	1 914	1 683	1 728	1 525
Average capital employed (b)	**8 684**	8 509	8 515	7 976	7 425
Return on average capital employed (percent) (b)	**44.7**	37.7	35.9	32.6	27.7
Cash flow from operating activities and asset sales (b)	**4 535**	3 905	3 799	3 891	3 414
Per-share information (dollars)					
Net income per share – basic	**4.39**	3.43	3.12	2.54	1.92
Net income per share – diluted	**4.36**	3.41	3.11	2.53	1.91
Dividends	**0.38**	0.35	0.32	0.31	0.29

(a) Operating revenues include $4,894 million for 2005 and $3,584 million for 2004 for purchases/sales contracts with the same counterparty. Associated costs were included in "purchases of crude oil and products". Effective January 1, 2006, these purchases/sales were recorded on a net basis.

(b) See frequently used financial terms on pages 34 to 35.

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.

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.

Imperial, with its resource base, financial strength, disciplined investment approach and technology portfolio, is well-positioned to participate in substantial investments to develop new Canadian energy supplies. While commodity prices remain volatile on a short-term basis depending upon supply and demand, Imperial's investment decisions are based on its long-term business outlook, 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. 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.

Business environment and risk assessment

Long-term business outlook

Economic and population growth are expected to remain the primary drivers of energy demand, globally and in North America. The company expects the global economy to grow at an average rate of about three percent per year through 2030. The combination of population and economic growth should lead to an increase in demand for primary energy at an average rate of 1.2 percent annually. The vast majority of this increase is expected to occur in developing countries.

Oil, gas and coal are expected to remain the predominant energy sources with approximately an 80 percent share of total energy. Oil and gas alone are expected to maintain close to a 60 percent share.

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 about half of one percent per year. Oil and gas are expected to continue to supply about 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 is expected to increase by about 25 percent or over 20 million barrels a day by 2030. Canada's oil resources, second only to Saudi Arabia, represent an important potential additional source of supply.

Natural gas is expected to be a major primary energy source globally, capturing about 35 percent of all incremental energy growth and approaching one-quarter of global energy supplies. Natural gas production from conventional sources in 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 and unconventional resources.

Upstream

Imperial produces crude oil and natural gas for sale into large North American markets. 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's fundamental Upstream business strategies guide our exploration, development, production and gas marketing activities. These strategies include identifying and pursuing all attractive exploration opportunities, investing in projects that deliver superior returns and maximizing profitability of existing oil and gas production. These strategies are underpinned by a relentless focus on operational excellence, commitment to innovative technologies, development of our employees and investment in the communities in which we operate.

Imperial has a large 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 heavy oil[a], oil sands[b] and unconventional natural gas and from Canada's North, where Imperial has large undeveloped resource opportunities.

Downstream

The downstream industry environment remains very competitive. Refining margins are the difference between what a refinery pays for its raw materials (primarily crude oil) and the wholesale market prices for the range of products produced (primarily gasoline, diesel fuel, heating oil, jet fuel and heavy fuel oil). While volatile from year to year, refining margins have declined at a rate of about one percent per year, on average, over the past 20 years in inflation adjusted terms. Intense competition in the retail fuels market similarly has tended to drive down real margins over time. 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 and products at the lowest total cost offer, have the lowest 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 8,000 barrels a day.

(a) Heavy oil typically is represented by crude oils with a viscosity of greater than 10,000 cP and is recovered through enhanced thermal operations.
(b) Oil sands are a semi-solid material composed of bitumen, sand, water and clays and are recovered through surface mining methods.

Imperial's fuels marketing business includes retail operations across Canada serving customers through about 1,900 Esso-branded retail service stations, of which about 570 are company-owned or leased, and wholesale and industrial operations through a network of 24 primary distribution terminals, as well as a secondary distribution network.

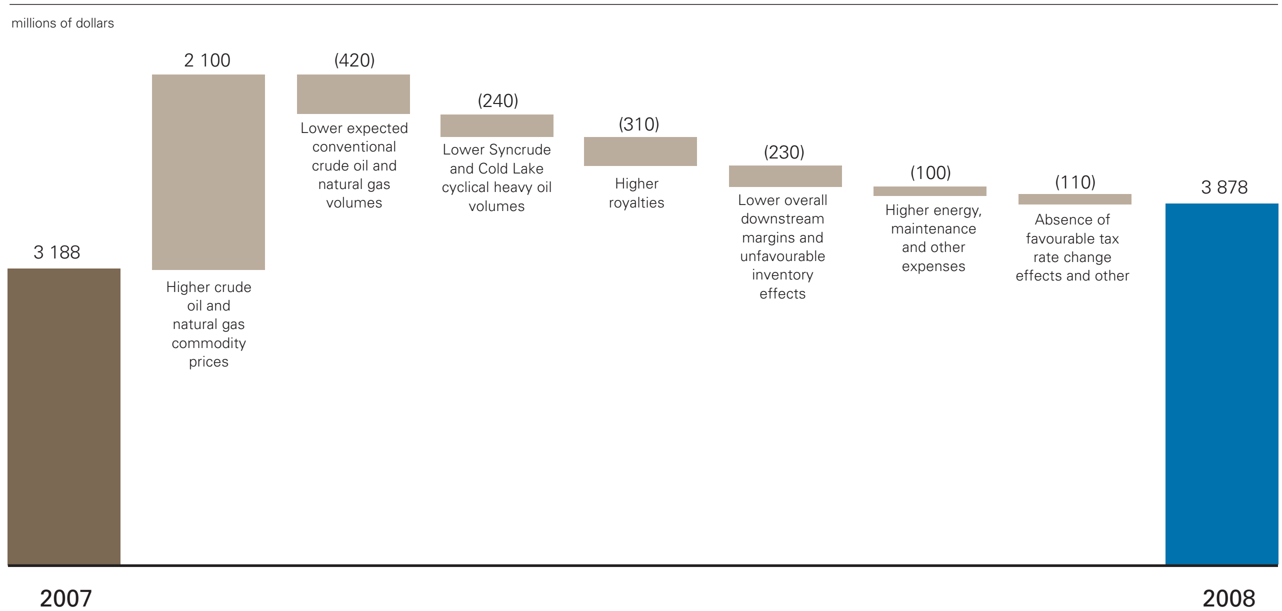
Chemical

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

Results of operations

Net income in 2008 of $3,878 million or $4.36 a share on a diluted basis was the best on record, exceeding the previous record achieved in 2007 of $3,188 million or $3.41 a share. Earnings increased primarily due to higher crude oil and natural gas commodity prices. Improved upstream realizations were partially offset by the negative impacts of lower upstream volumes, higher royalties, higher energy and maintenance costs and lower overall downstream margins.

Factors affecting Imperial's 2008 net income



The return on average capital employed was 45 percent, compared with 38 percent in 2007 (2006 – 36 percent).

Upstream

Net income was $2,923 million versus $2,369 million in 2007. Earnings benefited from higher overall crude oil and natural gas commodity prices totaling about $2,100 million. Their positive impact on earnings was partially offset by lower conventional volumes from expected reservoir decline of about $420 million, lower Syncrude volumes of about $135 million and lower cyclical Cold Lake heavy oil production of about $105 million. Earnings were also negatively impacted by higher royalties of about $310 million, higher energy, Syncrude maintenance, and other production costs totaling about $290 million, the absence of favourable effects of tax rate changes of about $170 million and lower gains from asset divestments of about $140 million.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (CONT'D)

Return on average capital employed was 65 percent, compared with 56 percent in 2007 (2006 – 60 percent).

Financial statistics

millions of dollars	**2008**	2007	2006	2005	2004
Net income	**2 923**	2 369	2 376	2 008	1 517
Operating revenues	**11 222**	8 685	8 456	8 189	6 580
Cash flow from operating activities and asset sales	**3 712**	2 661	3 151	2 805	2 395
Average capital employed	**4 526**	4 258	3 993	3 928	3 877
Return on average capital employed (percent)	**64.6**	55.6	59.5	51.1	39.1

World crude oil prices ended in 2008 much lower than the record levels reached earlier in the year. The price of Brent crude oil, a common benchmark of world oil markets, declined from a high of $144.22 (U.S.) a barrel in July to a low of $33.65 (U.S.) in December. For the year, the average price of Brent crude oil was $96.99 (U.S.) a barrel, up about 34 percent from 2007. The company's realizations on sales of Canadian conventional crude oil mirrored the same trends as world prices, ending 2008 at a level much lower than the average of the year.

Prices for Canadian heavy oil, including the company's heavy oil at Cold Lake, moved generally in line with that of the lighter crude oil. The price of Bow River, a benchmark Canadian heavy oil, increased by about 56 percent in 2008 from 2007 and fell much below the year's average by the end of the year.

Prices for Canadian natural gas in 2008 were higher than in the previous year. The average of 30-day spot prices for natural gas in Alberta was about $8.61 a thousand cubic feet in 2008, compared with $7.01 in 2007 (2006 – $7.41). The company's average realizations on natural gas sales were $8.69 a thousand cubic feet, compared with $6.95 in 2007 (2006 – $7.24).

Average realizations and prices

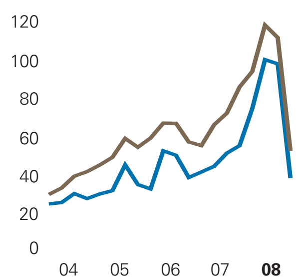
Canadian dollars	**2008**	2007	2006	2005	2004
Conventional crude oil realizations (a barrel)	**95.76**	71.70	68.58	64.48	48.96
Natural gas liquids realizations (a barrel)	**59.35**	47.92	40.75	40.00	33.78
Natural gas realizations (a thousand cubic feet)	**8.69**	6.95	7.24	9.00	6.78
Par crude oil price at Edmonton (a barrel)	**103.60**	77.67	73.75	69.86	53.26
Heavy oil price at Hardisty (Bow River, a barrel)	**83.91**	53.87	51.90	45.62	37.98

Gross production of heavy oil at the company's wholly owned facilities at Cold Lake was 147,000 barrels a day, compared with 154,000 barrels in 2007 (2006 – 152,000). Lower production was due to the cyclic nature of production at Cold Lake.

Gross production of synthetic crude oil from the Syncrude oil sands operation, in which the company has a 25 percent interest, was 289,000 barrels a day versus 305,000 barrels in 2007 (2006 – 258,000). Lower volumes were primarily the result of planned and unplanned maintenance activities during the year, including work to improve reliability performance. Imperial's share of average gross production decreased to 72,000 barrels a day from 76,000 barrels in 2007 (2006 – 65,000).

Crude oil prices

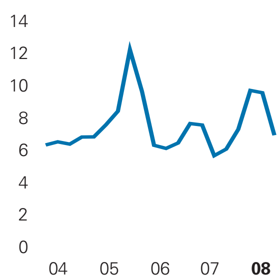
U.S. dollars a barrel – quarterly average



● Brent Crude
● Canadian Heavy Oil (Bow River)

Natural gas average prices

Canadian dollars a thousand cubic feet – Alberta 30-day spot*



*Natural Gas Exchange – Alberta Nova Inventory Transfer (NGX AB-NIT) Month Ahead Index Price

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (CONT'D)

Gross production of conventional oil decreased to 27,000 barrels a day from 29,000 barrels in 2007 (2006 – 31,000) as a result of natural decline in Western Canadian reservoirs.

Gross production of natural gas decreased to 310 million cubic feet a day from 458 million in 2007 (2006 – 556 million). The most significant reason for the lower production volumes was the completion of production, as expected, from the Wizard Lake gas cap blowdown.

Gross production of natural gas liquids (NGLs) available for sale averaged 10,000 barrels a day in 2008, down from 16,000 barrels in 2007 (2006 – 24,000), mainly due to the completion of production from Wizard Lake.

Crude oil and NGLs – production and sales (a)

thousands of barrels a day	**2008**		2007		2006		2005		2004	
	gross	**net**	gross	net	gross	net	gross	net	gross	net
Cold Lake	**147**	**124**	154	130	152	127	139	124	126	112
Syncrude	**72**	**62**	76	65	65	58	53	53	60	59
Conventional crude oil	**27**	**19**	29	21	31	23	38	29	43	33
Total crude oil production	**246**	**205**	259	216	248	208	230	206	229	204
NGLs available for sale	**10**	**8**	16	12	24	19	31	25	33	26
Total crude oil and NGL production	**256**	**213**	275	228	272	227	261	231	262	230
Cold Lake sales, include diluent (b)	**191**		200		198		183		167	
NGL sales	**11**		20		29		39		42	

Natural gas – production and sales (a)

millions of cubic feet a day	**2008**		2007		2006		2005		2004	
	gross	**net**	gross	net	gross	net	gross	net	gross	net
Production (c)	**310**	**249**	458	404	556	496	580	514	569	518
Sales	**288**		407		513		536		520	

(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) Diluent is natural gas condensate or other light hydrocarbons added to Cold Lake heavy oil 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.

Production costs increased mainly due to higher energy prices and Syncrude maintenance costs.

Downstream

Net income was $796 million, compared with $921 million in 2007. Earnings decreased primarily due to lower overall downstream margins and unfavourable inventory effects totaling about $230 million. Earnings were also lower due to higher planned maintenance costs of about $40 million and lower sales volumes of about $40 million. These factors were partially offset by a gain of $187 million from the sale of the company's equity investment in Rainbow Pipe Line Co. Ltd.

Return on average capital employed was 23 percent, compared with 28 percent in 2007 (2006 – 20 percent).

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (CONT'D)

Financial statistics

millions of dollars	**2008**	2007	2006	2005	2004
Net income	**796**	921	624	694	556
Operating revenues (a)	**26 941**	21 535	20 783	24 017	19 169
Cash flow from operating activities and asset sales	**539**	1 180	562	874	946
Average capital employed	**3 460**	3 257	3 161	2 906	2 831
Return on average capital employed (percent)	**23.0**	28.3	19.7	23.9	19.6

Sale of petroleum products

thousands of barrels a day (b)	**2008**	2007	2006	2005	2004
Gasolines	**204**	208	206	210	209
Heating, diesel and jet fuels	**157**	164	166	169	172
Heavy fuel oils	**30**	33	32	38	37
Lube oils and other products	**47**	43	49	48	44
Net petroleum product sales	**438**	448	453	465	462
Total domestic sales of petroleum products (percent)	**93.0**	94.8	95.1	95.3	93.0

Refinery utilization

thousands of barrels a day (b)	**2008**	2007	2006	2005	2004
Total refinery throughput (c)	**446**	442	442	466	467
Refinery capacity at December 31	**502**	502	502	502	502
Utilization of total refinery capacity (percent)	**89**	88	88	93	93

(a) Operating revenues in 2005 and prior years included amounts for purchases/sales with the same counterparty. Associated costs were included in "purchases of crude oil and products". Effective January 1, 2006, these purchases/sales were recorded on a net basis.
(b) Volumes a day are calculated by dividing total volumes for the year by the number of days in the year.
(c) Crude oil and feedstocks sent directly to atmospheric distillation units.

Industry refining margins were lower in 2008, compared with those in 2007, reflecting weakening demand and higher inventory levels. Marketing margins in 2008 were higher than those in 2007.

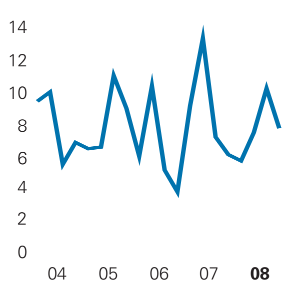
Refinery throughput was 89 percent of capacity in 2008, one percent higher than the previous year (2006 – 88 percent). Reliability improvements through the year were partially offset by the impact of declining economic conditions that did not support running the refineries to full capacity.

Downstream's total sales volumes, excluding those resulting from purchases/sales contracts with the same counterparty, were 438,000 barrels a day, down from 448,000 barrels in 2007 (2006 – 453,000). Lower industry demand was the main reason for the decline.

Manufacturing costs in 2008 were higher than the previous year primarily reflecting higher energy prices and planned maintenance costs.

Average refining margins

Canadian dollars a barrel



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

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (CONT'D)

Chemical

Net income was $100 million, compared with $97 million in 2007. Higher margins for polyethylene products were essentially offset by lower margins for intermediate products and lower sales volumes for both polyethylene and intermediate products.

Return on average capital employed was 50 percent, compared with 42 percent in 2007 (2006 – 55 percent).

Financial statistics

millions of dollars	**2008**	2007	2006	2005	2004
Net income	**100**	97	143	121	109
Operating revenues	**1 832**	1 635	1 704	1 665	1 509
Cash flow from operating activities and asset sales	**183**	109	162	94	126
Average capital employed	**199**	230	261	272	261
Return on average capital employed (percent)	**50.4**	42.2	54.8	44.6	41.8

Sales

thousands of tonnes a day (a)	**2008**	2007	2006	2005	2004
Polymers and basic chemicals	**2.1**	2.2	2.2	2.1	2.4
Intermediate and others	**0.7**	0.9	0.8	0.9	0.9
Total petrochemicals	**2.8**	3.1	3.0	3.0	3.3

(a) Calculated by dividing total volumes for the year by the number of days in the year.

The average industry price of polyethylene was $1,960 a tonne in 2008, up 18 percent from $1,666 a tonne in 2007 (2006 – $1,703), contributing to higher margins for polyethylene products.

Sales of chemical products were 2,800 tonnes a day, down from 3,100 tonnes in 2007 (2006 – 3,000 tonnes), primarily due to lower industry demand for both polyethylene and intermediate chemical products.

Manufacturing costs for 2008 were higher than 2007, reflecting higher energy prices.

Corporate and other

Net income effects from corporate and other was $59 million, versus negative $199 million last year. Favourable earnings effects were primarily due to lower share-based compensation charges and the absence of unfavourable effects of tax rate changes reported in 2007.

Liquidity and capital resources

Sources and uses of cash

millions of dollars	**2008**	2007	2006
Cash provided by/(used in)			
Operating activities	**4 263**	3 626	3 587
Investing activities	**(961)**	(620)	(965)
Financing activities	**(2 536)**	(3 956)	(2 125)
Increase/(decrease) in cash and cash equivalents	**766**	(950)	497
Cash and cash equivalents at end of year	**1 974**	1 208	2 158

Although the company issues long-term debt from time to time and maintains a revolving commercial paper program, internally generated funds normally 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 to ensure that it is secure and readily available to meet the company's cash requirements 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, to support cash flows in future periods, the company will need to continually find and develop new fields, and continue to develop and apply new technologies to existing fields, in order to maintain or increase production. 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.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (CONT'D)

The company's financial strength enables it to make large, long-term capital expenditures. Imperial's 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 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.

The company's registered pension plan is subject to an independent actuarial valuation that is required at least once every three years. The next such valuation will take place in 2010. Given the recent downturn in financial markets, the next valuation could require that Imperial increase its contributions to the plan over the next five years. The size of any required contribution will not be known until the valuation is completed. The company expects that it will meet any funding requirements without affecting current or future investment plans.

Cash flow from operating activities

Cash provided by operating activities was $4,263 million, versus $3,626 million in 2007 (2006 – $3,587 million). Higher cash flow in 2008 was primarily due to higher net income.

Cash flow from investing activities

Cash used in investing activities totaled $961 million in 2008, compared with $620 million in 2007 (2006 – $965 million). Higher spending on property, plant and equipment contributed to the increase.

Capital and exploration expenditures

Total capital and exploration expenditures were $1,363 million in 2008, compared with $978 million in 2007 (2006 – $1,209 million).

The funds were used mainly to advance the Kearl oil sands project, maintain Cold Lake production capacity, invest in environmental initiatives and upgrade the network of Esso retail outlets. About $250 million was spent on projects related to reducing the environmental impact of the company's operations and improving safety.

The following table shows the company's capital and exploration expenditures for Upstream during the five years ending December 31, 2008:

millions of dollars	**2008**	2007	2006	2005	2004
Heavy oil and oil sands	**740**	489	518	662	819
Production	**238**	150	237	232	234
Exploration	**132**	105	32	43	60
Total capital and exploration expenditures	**1 110**	744	787	937	1 113

For the Upstream segment, over 85 percent of the capital and exploration expenditures in 2008 were focused on growth opportunities. Significant expenditures during the year were for advancing the Kearl oil sands project and ongoing development drilling at Cold Lake. Other 2008 investments included facilities improvements at Syncrude, drilling at Horn River and conventional fields in Western Canada and a 3-D seismic program in the Beaufort Sea.

Kearl is an oil sands mining project located northeast of Fort McMurray, Alberta. Regulatory approvals were received and the project is planned to advance in phases. Production from the first phase of Kearl is expected to average approximately 110,000 barrels of bitumen a day before royalties, of which Imperial's share would be about 78,000 barrels. Imperial's share of proven reserves developed by the first phase is 807 million barrels and was added to the company's proven mined bitumen reserves in 2008.

About $500 million had been invested in Kearl by the end of 2008. Activities in 2008 focused on engineering work to define the project design and execution plan. Other activities in 2008 also included access road construction, site preparation and earthworks. Significant progress has also been made in transportation system agreements.

Imperial has acquired exploration licenses to about 76,000 net acres in British Columbia's natural gas prone Horn River area. Exploration drilling and evaluation commenced in 2008.

Planned capital and exploration expenditures in the Upstream segment are expected to be about $1.8 billion in 2009, with over 80 percent of the total focused on growth opportunities. Investments are mainly planned for the Kearl oil sands project and development drilling at Cold Lake. Other investments will include facilities improvements at Syncrude, development drilling at conventional oil and gas operations in Western Canada and exploration at Horn River.

The following table shows the company's capital expenditures in the Downstream segment during the five years ending December 31, 2008:

millions of dollars	**2008**	2007	2006	2005	2004
Refining and supply	**160**	120	248	368	178
Marketing	**61**	63	97	91	85
Other (a)	**11**	4	16	19	20
Total capital expenditures	**232**	187	361	478	283

(a) Consists primarily of real estate purchases.

For the Downstream segment, capital expenditures were $232 million in 2008, compared with $187 million in 2007 (2006 – $361 million). In 2008, Downstream capital expenditures focused mainly on improving air emissions, increasing refinery capacity utilization and upgrading the retail network.

Capital expenditures for the Downstream segment in 2009 are expected to be about $400 million, and will be mainly directed to increasing sulphur recovery to further reduce sulphur dioxide emissions, upgrading water management systems as well as enhancing feedstock flexibility and energy efficiency. Retail projects will continue to focus on network upgrades in major urban markets.

The following table shows the company's capital expenditures for its Chemical operations during the five years ending December 31, 2008:

millions of dollars	**2008**	2007	2006	2005	2004
Capital expenditures	**13**	11	13	19	15

Of the capital expenditures for the Chemical segment in 2008, the major investment was directed to upgrading water management systems, improving safety and increasing feedstock flexibility.

Planned capital expenditures for Chemical in 2009 is about $35 million and will include continued investments to increase feedstock flexibility and further upgrade water management and safety systems.

Total capital and exploration expenditures for the company in 2009, which will focus mainly on growth and productivity improvements, are expected to total about $2.2 billion and to be financed from internally generated funds.

Cash flow from financing activities

Cash used in financing activities was $2,536 million in 2008, compared with $3,956 million in 2007 (2006 – $2,125 million).

In June, another 12-month share repurchase program was implemented. During 2008, the company purchased 44.3 million shares for $2,210 million (2007 – 50.5 million shares for $2,358 million), including shares purchased from ExxonMobil. Since Imperial initiated its first share repurchase program in 1995, the company has purchased 890.4 million shares – representing about 51 percent of the total outstanding at the start of the program – with resulting distributions to shareholders of over $15 billion.

The company declared dividends totaling 38 cents a share in 2008, up from 35 cents in 2007 (2006 – 32 cents). Regular annual per-share dividends paid have increased in each of the past 14 years and, since 1986, payments per share have grown by 102 percent.

Total debt outstanding at the end of 2008, excluding the company's share of equity company debt, was $143 million, compared with $146 million at the end of 2007 (2006 – $1,437 million). Debt represented two percent of the company's capital structure at the end of 2008, unchanged from the end of 2007 (2006 – 17 percent).

Debt-related interest incurred in 2008, before capitalization of interest, was $8 million, compared with $62 million in 2007 (2006 – $63 million). The average effective interest rate on the company's debt was 5.5 percent in 2008, compared with 4.9 percent in 2007 (2006 – 4.4 percent).

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (CONT'D)

Financial percentages, ratios and credit rating

	2008	2007	2006	2005	2004
Total debt as a percentage of capital (a)	**2**	2	17	18	19
Interest coverage ratios					
Earnings basis (b)	**661**	72	66	88	83
Cash-flow basis (c)	**721**	82	77	101	108
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 39) and the company's share of equity company debt, divided by debt and shareholders' equity (page 39).
(b) Net income (page 38), debt-related interest before capitalization (page 58, note 13) and income taxes (page 38), divided by debt-related interest before capitalization.
(c) Cash flow from net income adjusted for other non-cash items (page 41), current income tax expense (page 48, note 4) and debt-related interest before capitalization (page 58, note 13) 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.

Commitments

The following table shows the company's commitments outstanding at December 31, 2008. It combines data from the consolidated balance sheet and from individual notes to the consolidated financial statements.

	Financial	Payment due by period			
millions of dollars	Statement note reference	2009	2010 to 2013	2014 and beyond	Total amount
Capitalized lease obligations (a)	Note 14	4	15	19	38
Operating leases (b)	Note 14	64	210	158	432
Unconditional purchase obligations (c)	Note 10	127	262	31	420
Firm capital commitments (d)		251	80	–	331
Pension and other post-retirement obligations (e)	Note 5	253	203	740	1 196
Asset retirement obligations (f)	Note 6	42	309	360	711
Other long-term purchase agreements (g)		302	506	166	974

(a) Capital lease obligations primarily relate to the capital lease for marine services.
(b) Minimum commitments for operating leases, shown on an undiscounted basis, primarily cover office buildings, rail cars and service stations.
(c) Unconditional purchase obligations are those long-term commitments that are non-cancelable and that third parties have used to secure financing for the facilities that will provide the contracted goods and services. They mainly pertain to pipeline throughput agreements.
(d) Firm capital commitments related to capital projects, shown on an undiscounted basis. The largest commitments outstanding at year-end 2008 were $98 million associated with the company's share of exploration projects.
(e) The amount by which the benefit obligations exceeded the fair value of fund assets for pension and other post-retirement plans at year-end. The payments by period include expected contributions to funded pension plans in 2009 and estimated benefit payments for unfunded plans in all years.
(f) Asset retirement obligations represent the fair value of legal obligations associated with site restoration on the retirement of assets with determinable useful lives.
(g) Other long-term purchase agreements are non-cancelable, long-term commitments other than unconditional purchase obligations. They include primarily raw material supply and transportation services agreements.

Unrecognized tax benefits totaling $150 million have not been included in the company's commitments table because the company does not expect there will be any cash impact from the final settlements as sufficient funds have been deposited with the Canada Revenue Agency. Further details on the unrecognized tax benefits can be found in note 4 to the consolidated financial statements on page 48.

The company was contingently liable at December 31, 2008 for a maximum of $79 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.

Litigation and other contingencies

As discussed in note 10 to the consolidated financial statements on page 56, a variety of claims have been made 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.

The Alberta government enacted changes to the oil and gas and generic oil sands royalty regime effective 2009. The impacts of the changes have been incorporated in the company's 2008 oil and gas reserves and mined bitumen reserves calculation, where appropriate. In November 2008, Imperial, along with the other Syncrude joint-venture owners, signed an agreement with the Government of Alberta to amend the existing Syncrude Crown Agreement. Under the amended agreement, beginning January 1, 2010, Syncrude will begin transitioning to the new oil sands royalty regime by paying additional royalties, the exact amount of which will depend on production levels from 2010 to 2015. Also, beginning January 1, 2009, Syncrude's royalty will be based on bitumen value with upgrading costs and revenues excluded from the calculation. The impacts of the amended agreement have been incorporated in the 2008 synthetic crude oil reserves calculation.

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, synthetic crude oil and mined bitumen reserve quantities are used as the basis for calculating unit-of-production depreciation rates and for evaluating 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 volumes, the mining plan, historical extraction recovery and upgrading yield factors, installed plant operating capacity and operating approval limits. Estimates of mined bitumen reserves are based on detailed geological and engineering assessments of in-place crude bitumen volumes, the mining plan, demonstrated extraction recovery factors, planned 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 within 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. Notably, the company does not use reserve targets to determine compensation. 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 significant funding commitments toward the development of the reserves prior to reporting as proved.

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

The year-end oil and gas reserves volumes as well as the reserves change categories shown in the proved reserves tables are calculated using December 31 prices and costs. These reserves quantities are also used in calculating unit-of-production depreciation rates and in calculating the standardized measure of discounted net cash flow. We understand that the use of December 31 prices and costs is intended to provide a point in time measure to calculate reserves and to enhance comparability between companies. However, the use of year-end prices for reserves estimation introduces short-term price volatility into the process, which is inconsistent with the long-term nature of the upstream business, since annual adjustments are required based on prices occurring on a single day. As a result, the use of prices from a single date is not relevant to the investment decisions made by the company.

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 in year-end prices and costs that are used in the determination of reserves. This category can also include significant changes in either development strategy or production equipment/facility capacity. The quantities shown in the revisions category under heavy oil proved reserves in 2006 on page 62 were due mainly to the changes in year-end prices and costs that were used in the determination of reserves. 807 million barrels of mined bitumen reserves were added in 2008 in the revisions category, reflecting the company's share of reserves being developed in the first phase of the Kearl oil sands project.

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. 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 upstream 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. While the revisions the company has made in the past are an indicator of variability, they have had little impact on the unit-of-production rates of depreciation.

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 company performs asset valuation analyses on an ongoing basis as a part of its asset management program. These analyses monitor the performance of assets against corporate objectives. They also assist the company in assessing whether the carrying amounts of any of its assets may not be recoverable. In addition to estimating oil and gas reserve volumes in conducting these analyses, it is also necessary to estimate future oil and gas prices. Trigger events for impairment evaluations 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 significantly, 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 price assumptions developed in the annual planning and budgeting process for crude oil and natural gas markets, petroleum products and chemicals. These are the same price assumptions that are used for capital investment decisions. Volumes are based on individual field production profiles, which are also updated annually.

The standardized measure of discounted future cash flows on page 61 is based on the year-end 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.

Pension 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 8.00 percent used in 2008 compares to actual returns of 5.00 percent and 8.31 percent achieved over the last 10- and 20-year periods ending December 31, 2008. 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 5 to the consolidated financial statements on page 49. At Imperial, differences between actual returns on plan assets and the long-term expected returns are not recorded in pension expense in the year the differences occur. Such differences are deferred, along with other actuarial gains and losses, and are amortized into pension expense over the expected remaining service life of employees. Pension expense represented less than one percent of total expenses in 2008.

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 2008, the obligations were discounted at six percent and the accretion expense was $29 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. Asset retirement obligations for these facilities generally become firm at the time the facilities are permanently shut down and dismantled. These obligations may include the costs of asset disposal and additional soil remediation. However, these sites have indeterminate lives based on plans for continued operations, and as such, the fair value of the conditional legal obligations cannot be measured, since it is impossible to estimate the future settlement dates of such obligations. 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.

Tax contingencies

The operations of the company are complex, and related tax interpretations, regulations and legislation are continually changing. Significant management judgment is required in the accounting for income tax contingencies and tax disputes because the outcomes are often difficult to predict.

GAAP requires recognition and measurement of uncertain tax positions that the company has taken or expects to take in its income tax returns. The benefit of an uncertain tax position can only be recognized in the financial statements if management concludes that it is more likely than not that the position will be sustained with the tax authorities. For a position that is likely to be sustained, the benefit recognized in the financial statements is measured at the largest amount that is greater than 50 percent likely of being realized. A reserve is established for the difference between a position taken in an income tax return and the amount recognized in the financial statements. The company's unrecognized tax benefits and a description of open tax years are summarized in note 4 to the consolidated financial statements on page 48.

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.

During 2008, credit markets tightened, and the global economy slowed. In 2009, the company does not expect to be dependent on credit markets to fund normal operations or investment plans.

In April 2007, the Government of Canada announced its intent to introduce a set of regulations to limit emissions of greenhouse gas and air pollutants from major industrial facilities in Canada, although the details of the regulations have not been finalized. Consequently, attempts to assess the impact on the company are premature. The company will continue to monitor the development of legal requirements in this area.

In the Province of Alberta, regulations governing greenhouse gas emissions from large industrial facilities came into effect July 1, 2007. Compliance costs were not material in 2007 and 2008, and the company does not expect ongoing compliance costs to have a material adverse effect on the company's operations or financial condition.

The U.S. Energy Independence and Security Act of 2007 precludes agencies of the U.S. federal government from procuring motive fuels from non-conventional petroleum sources that have lifecycle greenhouse gas emissions greater than equivalent conventional fuel. This may have implications for the company's marketing in the United States of some heavy oil and oil sands production, but the impact cannot be determined at this time.

Other risks, such as changes in international commodity prices and currency-exchange rates, are beyond the company's control. The company does not use derivative markets to speculate on the future direction of currency or commodity prices. The company's size, strong financial position and the complementary nature of its Upstream, Downstream and Chemical 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 sensitivities table below, which 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		
Three dollars (U.S.) a barrel change in crude oil prices	+ (-)	$ 150
Seventy cents a thousand cubic feet change in natural gas prices	+ (-)	$ 6
One dollar (U.S.) a barrel change in sales margins for total petroleum products	+ (-)	$ 140
One cent (U.S.) a pound change in sales margins for polyethylene	+ (-)	$ 7
Eight cents decrease (increase) in the value of the Canadian dollar versus the U.S. dollar	+ (-)	$ 300

(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 2008. 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 crude oil prices increased from 2007 year-end by about $13 million (after-tax) for each one U.S.-dollar a barrel difference. A decrease in the value of the Canadian dollar has increased the impact of U.S. dollar denominated crude oil prices on the company's revenues and earnings.

The presentation of the sensitivity of net income to changes in sales margins for total petroleum products has changed from a one cent (U.S.) a litre basis to a one dollar (U.S.) a barrel basis to conform to industry benchmarks' unit of measure. The sensitivity of net income to changes in sales margins for total petroleum products was about $140 million (after-tax) for each one dollar (U.S.) a barrel difference at 2008 year-end, an increase of about $25 million from 2007 year-end. A decrease in the value of the Canadian dollar has increased the impact of U.S. dollar denominated crude oil and petroleum products prices on the company's revenues and earnings.

Frequently used financial terms

Listed below are definitions of three 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	**2008**	2007	2006
Business uses: asset and liability perspective			
Total assets	**17 035**	16 287	16 141
Less: total current liabilities excluding short-term debt and current portion of long-term debt	**(4 040)**	(4 833)	(4 270)
Less: total long-term liabilities excluding long-term debt	**(3 787)**	(3 385)	(3 028)
Add: Imperial's share of equity company debt	**40**	50	55
Total capital employed	**9 248**	8 119	8 898

millions of dollars	**2008**	2007	2006
Total company sources: debt and equity perspective			
Short-term debt and current portion of long-term debt	**109**	108	1 078
Long-term debt	**34**	38	359
Shareholders' equity	**9 065**	7 923	7 406
Add: Imperial's share of equity company debt	**40**	50	55
Total capital employed	**9 248**	8 119	8 898

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (CONT'D)

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. Additional measures, which tend to be more cash flow based, are used to make investment decisions.

millions of dollars	**2008**	2007	2006
Net income	**3 878**	3 188	3 044
Financing costs (after tax), including Imperial's share of equity companies	**2**	18	10
Net income excluding financing costs	**3 880**	3 206	3 054
Average capital employed	**8 684**	8 509	8 515
Return on average capital employed (percent)	**44.7**	37.7	35.9

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	**2008**	2007	2006
Cash from operating activities	**4 263**	3 626	3 587
Proceeds from asset sales	**272**	279	212
Total cash flow from operating activities and asset sales	**4 535**	3 905	3 799

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, 2008.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the company's internal control over financial reporting as of December 31, 2008, as stated in their report which is included herein.

B.H. March

Chairman, president and chief executive officer

P.A. Smith

Senior vice-president, finance and administration, and treasurer
(Principal accounting officer and principal financial officer)

February 24, 2009

AUDITORS' REPORT

To the Shareholders of Imperial Oil Limited
We have completed integrated audits of Imperial Oil Limited's 2008, 2007 and 2006 consolidated financial statements and of its internal control over financial reporting as of December 31, 2008. Our opinions, based on our audits, are presented below.

Consolidated financial statements
In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of Imperial Oil Limited and its subsidiaries at December 31, 2008 and December 31, 2007, and the results of their operations and their cash flows for each of the years in the three year period ended December 31, 2008 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 statement presentation. We believe that our audits provide a reasonable basis for our opinion.

Internal control over financial reporting
Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's report on internal control over financial reporting. Our responsibility is to express an opinion on the 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, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

PricewaterhouseCoopers LLP.

Chartered Accountants
Calgary, Alberta, Canada
February 24, 2009

CONSOLIDATED STATEMENT OF INCOME (U.S. GAAP)

millions of Canadian dollars For the years ended December 31	**2008**	2007	2006
Revenues and other income			
Operating revenues (a) (b)	**31 240**	25 069	24 505
Investment and other income (note 9)	**339**	374	283
Total revenues and other income	**31 579**	25 443	24 788
Expenses			
Exploration	**132**	106	32
Purchases of crude oil and products (c)	**18 865**	14 026	13 793
Production and manufacturing (d)	**4 228**	3 474	3 446
Selling and general	**1 038**	1 335	1 284
Federal excise tax (a)	**1 312**	1 307	1 274
Depreciation and depletion	**728**	780	831
Financing costs (note 13)	**–**	36	28
Total expenses	**26 303**	21 064	20 688
Income before income taxes	**5 276**	4 379	4 100
Income taxes (note 4)	**1 398**	1 191	1 056
Net income	**3 878**	3 188	3 044
Per-share information (Canadian dollars)			
Net income per common share – basic (note 11)	**4.39**	3.43	3.12
Net income per common share – diluted (note 11)	**4.36**	3.41	3.11
Dividends	**0.38**	0.35	0.32

(a) Operating revenues include federal excise tax of $1,312 million (2007 – $1,307 million, 2006 – $1,274 million).
(b) Operating revenues include amounts from related parties of $2,150 million (2007 – $1,772 million, 2006 – $1,955 million), (note 15).
(c) Purchases of crude oil and products include amounts from related parties of $4,729 million (2007 – $3,331 million, 2006 – $3,937 million), (note 15).
(d) Production and manufacturing expenses include amounts to related parties of $161 million (2007 – $194 million, 2006 – $156 million), (note 15).

The information on pages 42 through 59 is an integral part of these consolidated financial statements.

CONSOLIDATED BALANCE SHEET (U.S. GAAP)

millions of Canadian dollars At December 31	2008	2007
Assets		
Current assets		
Cash	**1 974**	1 208
Accounts receivable, less estimated doubtful amounts	**1 455**	2 132
Inventories of crude oil and products (note 12)	**673**	566
Materials, supplies and prepaid expenses	**180**	128
Deferred income tax assets (note 4)	**361**	660
Total current assets	**4 643**	4 694
Long-term receivables, investments and other long-term assets	**881**	766
Property, plant and equipment,		
less accumulated depreciation and depletion (note 3)	**11 248**	10 561
Goodwill (note 3)	**204**	204
Other intangible assets, net	**59**	62
Total assets (note 3)	**17 035**	16 287
Liabilities		
Current liabilities		
Notes and loans payable (note 13)	**109**	108
Accounts payable and accrued liabilities (a)	**2 542**	3 335
Income taxes payable	**1 498**	1 498
Total current liabilities	**4 149**	4 941
Capitalized lease obligations (note 14)	**34**	38
Other long-term obligations (note 6)	**2 298**	1 914
Deferred income tax liabilities (note 4)	**1 489**	1 471
Total liabilities	**7 970**	8 364
Commitments and contingent liabilities (note 10)		
Shareholders' equity		
Common shares at stated value (note 11)(b)	**1 528**	1 600
Earnings reinvested	**8 484**	7 071
Accumulated other comprehensive income	**(947)**	(748)
Total shareholders' equity	**9 065**	7 923
Total liabilities and shareholders' equity	**17 035**	16 287

(a) Accounts payable and accrued liabilities include amounts to related parties of $96 million (2007 – $260 million), (note 15).
(b) Number of common shares outstanding was 859 million (2007 – 903 million), (note 11).

The information on pages 42 through 59 is an integral part of these consolidated financial statements.

Approved by the directors

B.H. March
Chairman, president and
chief executive officer

P.A. Smith
Senior vice-president,
finance and administration, and treasurer

CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY (U.S. GAAP)

millions of Canadian dollars At December 31	**2008**	2007	2006
Common shares at stated value (note 11)			
At beginning of year	**1 600**	1 677	1 747
Issued under the stock option plan	**7**	12	10
Share purchases at stated value	**(79)**	(89)	(80)
At end of year	**1 528**	1 600	1 677
Earnings reinvested			
At beginning of year	**7 071**	6 462	5 466
Cumulative effect of accounting change (note 4)	**–**	14	–
Net income for the year	**3 878**	3 188	3 044
Share purchases in excess of stated value	**(2 131)**	(2 269)	(1 737)
Dividends	**(334)**	(324)	(311)
At end of year	**8 484**	7 071	6 462
Accumulated other comprehensive income			
At beginning of year	**(748)**	(733)	(580)
Post-retirement benefits liability adjustment (note 5)	**(283)**	(87)	(733)
Amortization of post-retirement benefits liability adjustment included in net periodic benefit cost	**84**	72	–
Minimum pension liability adjustment (note 5)	**–**	–	580
At end of year	**(947)**	(748)	(733)
Shareholders' equity at end of year	**9 065**	7 923	7 406
Comprehensive income for the year			
Net income for the year	**3 878**	3 188	3 044
Other comprehensive income			
Post-retirement benefits liability adjustment	**(199)**	(15)	–
Minimum pension liability adjustment	**–**	–	334
Total comprehensive income for the year	**3 679**	3 173	3 378

The information on pages 42 through 59 is an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENT OF CASH FLOWS (U.S. GAAP)

millions of Canadian dollars Inflow/(outflow) For the years ended December 31	**2008**	2007	2006
Operating activities			
Net income	**3 878**	3 188	3 044
Adjustments for non-cash items:			
Depreciation and depletion	**728**	780	831
(Gain)/loss on asset sales	**(241)**	(215)	(134)
Deferred income taxes and other	**387**	75	292
Changes in operating assets and liabilities:			
Accounts receivable	**679**	(261)	203
Inventories and prepaids	**(159)**	13	(97)
Income taxes payable	**–**	(77)	(225)
Accounts payable	**(798)**	250	(86)
All other items – net (a)	**(211)**	(127)	(241)
Cash from operating activities	**4 263**	3 626	3 587
Investing activities			
Additions to property, plant and equipment and intangibles	**(1 231)**	(899)	(1 177)
Proceeds from asset sales	**272**	279	212
Loans to equity company	**(2)**	–	–
Cash from (used in) investing activities	**(961)**	(620)	(965)
Financing activities			
Short-term debt – net	**–**	(65)	72
Repayment of long-term debt	**–**	(1 722)	(70)
Long-term debt issued	**–**	500	–
Reduction in capitalized lease obligations	**(3)**	(4)	(4)
Issuance of common shares under stock option plan	**7**	12	10
Common shares purchased (note 11)	**(2 210)**	(2 358)	(1 818)
Dividends paid	**(330)**	(319)	(315)
Cash from (used in) financing activities	**(2 536)**	(3 956)	(2 125)
Increase (decrease) in cash	**766**	(950)	497
Cash at beginning of year	**1 208**	2 158	1 661
Cash at end of year (b)	**1 974**	1 208	2 158

(a) Includes contribution to registered pension plans of $165 million (2007 – $163 million, 2006 – $395 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 59 is an integral part of these consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The accompanying consolidated financial statements and the supporting and supplemental material are the responsibility of the management of Imperial Oil Limited.

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 in the United States of America. The financial statements include certain estimates that reflect management's best judgment. Certain reclassifications to prior years have been made to conform to the 2008 presentation. All amounts are in Canadian dollars unless otherwise indicated.

1. Summary of significant accounting policies

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 Upstream activities 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.

Inventories
Inventories are recorded at the lower of cost or current market 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. The company carries as an asset exploratory well costs if (a) the well found a sufficient quantity of reserves to justify its completion as a producing well and (b) the company is making sufficient progress assessing the reserves and the economic and operating viability of the project. Exploratory well costs not meeting these criteria are charged to expense. 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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONT'D)

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. Acquisition costs of proved properties are amortized using a unit-of-production method, computed on the basis of total proved oil and gas reserves. Unit-of-production depreciation is applied to those wells, plant and equipment assets associated with productive depletable properties and the unit-of-production rates are based on the amount of proved developed reserves of oil and gas. 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 and natural gas commodity prices and foreign-currency exchange rates. Annual volumes are based on individual field production profiles, which are also updated annually.

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.

Acquisition costs for the company's oil sands[a] operation are capitalized as incurred. Oil sands exploration costs are expensed as incurred. The capitalization of project development costs begins when there are no major uncertainties that exist which would preclude management from making a significant funding commitment within a reasonable time period. The company expenses stripping costs during the production phase as incurred.

Depreciation of oil sands mining and extraction assets begins when bitumen ore is produced on a sustained basis, and depreciation of bitumen upgrading assets begins when feed is introduced to the upgrading unit and maintained on a continuous basis. Assets under construction are not depreciated. Investments in extraction facilities, which separate the crude from sand, as well as the upgrading facilities, are depreciated on a unit-of-production method based on proven reserves. Investments in mining and transportation systems are generally depreciated on a straight-line basis over a 15-year life. Other mining related infrastructure costs that are of a long-term nature intended for continued use in or to provide long-term benefit to the operation, such as pre-production stripping, certain roads, etc., are depreciated on a unit-of-production basis based on proven reserves.

Oil sands assets held and used by the company are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amounts are not recoverable. The impairment evaluation for oil sands assets is based on a comparison of undiscounted cash flows to book carrying value.

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. The project construction phase commences with the development of the detailed engineering design and ends when the constructed assets are ready for their intended use.

(a) Oil sands are a semi-solid material composed of bitumen, sand, water and clays and are recovered through surface mining methods. Currently, the company's oil sands production volumes are the company's share of production volumes in the Syncrude joint venture, and the company's reserves from oil sands operations are the company's share of synthetic crude oil reserves in the Syncrude joint venture and the company's share of mined bitumen reserves in the Kearl oil sands project.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONT'D)

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 soil remediation and 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. Asset retirement obligations for these facilities generally become firm at the time the facilities are permanently shut down and dismantled. These obligations may include the costs of asset disposal and additional soil remediation. However, these sites have indeterminate lives based on plans for continued operations, and as such, the fair value of the conditional legal obligations cannot be measured, since it is impossible to estimate the future settlement dates of such obligations. Provision for environmental liabilities of these 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 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.

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.

Purchases and sales of inventory with the same counterparty that are entered into in contemplation of one another are combined and recorded as exchanges measured at the book value of the item sold.

Share-based compensation
The company awards share-based compensation to employees in the form of restricted stock units. Compensation expense is measured each reporting period based on the company's current stock price and is recorded as "selling and general" expenses in the consolidated statement of income over the requisite service period of each award. See note 8 to the consolidated financial statements for further details.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONT'D)

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. Accounting change for fair value measurement

Effective January 1, 2008, the company adopted the Financial Accounting Standards Board's (FASB) Statement No. 157 (SFAS 157), "Fair Value Measurements" for financial assets and liabilities that are measured at fair value and nonfinancial assets and liabilities that are remeasured at fair value on a recurring basis. SFAS 157 defines fair value, establishes a framework for measuring fair value when an entity is required to use a fair value measure for recognition or disclosure purposes and expands the disclosures about fair value measurements. The initial application of SFAS 157 had no material impact on the company's financial statements. Effective January 1, 2009, SFAS 157 is applicable to all nonfinancial assets and liabilities that are measured at fair value.

3. Business segments

The company operates its business in Canada. The Upstream, Downstream and Chemical functions best define the operating segments of the business that are reported separately. The factors used to identify these reportable segments are based on the nature of the operations that are undertaken by each segment and the structure of the company's internal organization. The Upstream segment is organized and operates to explore for and ultimately produce crude oil and its equivalent, and natural gas. The Downstream segment is organized and operates to refine crude oil into petroleum products and the distribution and marketing of these products. The Chemical segment is organized and operates to manufacture and market hydrocarbon-based chemicals and chemical products. The above segmentation has been the long-standing practice of the company and is broadly understood across the petroleum and petrochemical industries.

These 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 and post-retirement benefits liability adjustment. Net income in this segment primarily includes financing costs, interest income and share-based incentive compensation expenses.

Segment accounting policies are the same as those described in the summary of significant accounting policies. Upstream, Downstream and Chemical 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. Intersegment sales are made essentially at prevailing market prices. Assets and liabilities that are not identifiable by segment are allocated.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONT'D)

	Upstream (a)			Downstream			Chemical		
millions of dollars	**2008**	2007	2006	**2008**	2007	2006	**2008**	2007	2006
Revenues and other income									
External sales (b)	**5 819**	4 539	4 619	**24 049**	19 230	18 527	**1 372**	1 300	1 359
Intersegment sales	**5 403**	4 146	3 837	**2 892**	2 305	2 256	**460**	335	345
Investment and other income	**18**	233	111	**271**	52	105	**1**	–	–
	11 240	8 918	8 567	**27 212**	21 587	20 888	**1 833**	1 635	1 704
Expenses									
Exploration	**132**	106	32	**–**	–	–	**–**	–	–
Purchases of crude oil and products	**3 995**	3 113	2 841	**22 223**	16 469	16 178	**1 401**	1 230	1 209
Production and manufacturing	**2 569**	2 057	1 994	**1 452**	1 232	1 266	**208**	185	189
Selling and general (c)	**6**	8	13	**998**	987	1 018	**72**	71	76
Federal excise tax	**–**	–	–	**1 312**	1 307	1 274	**–**	–	–
Depreciation and depletion	**474**	519	584	**234**	244	233	**12**	12	11
Financing costs (note 13)	**2**	4	2	**(5)**	1	6	**–**	–	–
Total expenses	**7 178**	5 807	5 466	**26 214**	20 240	19 975	**1 693**	1 498	1 485
Income before income taxes	**4 062**	3 111	3 101	**998**	1 347	913	**140**	137	219
Income taxes (note 4)									
Current	**1 051**	682	602	**(56)**	491	174	**37**	42	60
Deferred	**88**	60	123	**258**	(65)	115	**3**	(2)	16
Total income tax expense	**1 139**	742	725	**202**	426	289	**40**	40	76
Net income	**2 923**	2 369	2 376	**796**	921	624	**100**	97	143
Cash flow from (used in) operating activities	**3 699**	2 411	3 024	**280**	1 151	507	**183**	109	161
Capital and exploration expenditures	**1 110**	744	787	**232**	187	361	**13**	11	13
Property, plant and equipment									
Cost	**16 344**	15 285	14 926	**6 776**	6 655	6 581	**732**	718	702
Accumulated depreciation and depletion	**(8 832)**	(8 474)	(8 255)	**(3 452)**	(3 320)	(3 178)	**(514)**	(496)	(484)
Net property, plant and equipment (d) (e)	**7 512**	6 811	6 671	**3 324**	3 335	3 403	**218**	222	218
Total assets	**8 758**	8 171	7 513	**6 038**	6 727	6 450	**431**	476	504

	Corporate and other			Eliminations			Consolidated		
millions of dollars	**2008**	2007	2006	**2008**	2007	2006	**2008**	2007	2006
Revenues and other income									
External sales (b)	**–**	–	–	**–**	–	–	**31 240**	25 069	24 505
Intersegment sales	**–**	–	–	**(8 755)**	(6 786)	(6 438)	**–**	–	–
Investment and other income	**49**	89	67	**–**	–	–	**339**	374	283
	49	89	67	**(8 755)**	(6 786)	(6 438)	**31 579**	25 443	24 788
Expenses									
Exploration	**–**	–	–	**–**	–	–	**132**	106	32
Purchases of crude oil and products	**–**	–	–	**(8 754)**	(6 786)	(6 435)	**18 865**	14 026	13 793
Production and manufacturing	**–**	–	–	**(1)**	–	(3)	**4 228**	3 474	3 446
Selling and general (c)	**(38)**	269	177	**–**	–	–	**1 038**	1 335	1 284
Federal excise tax	**–**	–	–	**–**	–	–	**1 312**	1 307	1 274
Depreciation and depletion	**8**	5	3	**–**	–	–	**728**	780	831
Financing costs (note 13)	**3**	31	20	**–**	–	–	**–**	36	28
Total expenses	**(27)**	305	200	**(8 755)**	(6 786)	(6 438)	**26 303**	21 064	20 688
Income before income taxes	**76**	(216)	(133)	**–**	–	–	**5 276**	4 379	4 100
Income taxes (note 4)									
Current	**(27)**	(52)	(60)	**–**	–	–	**1 005**	1 163	776
Deferred	**44**	35	26	**–**	–	–	**393**	28	280
Total income tax expense	**17**	(17)	(34)	**–**	–	–	**1 398**	1 191	1 056
Net income	**59**	(199)	(99)	**–**	–	–	**3 878**	3 188	3 044
Cash flow from (used in) operating activities	**101**	(45)	(105)	**–**	–	–	**4 263**	3 626	3 587
Capital and exploration expenditures	**8**	36	48	**–**	–	–	**1 363**	978	1 209
Property, plant and equipment									
Cost	**313**	304	269	**–**	–	–	**24 165**	22 962	22 478
Accumulated depreciation and depletion	**(119)**	(111)	(104)	**–**	–	–	**(12 917)**	(12 401)	(12 021)
Net property, plant and equipment (d) (e)	**194**	193	165	**–**	–	–	**11 248**	10 561	10 457
Total assets	**1 982**	1 251	2 145	**(174)**	(338)	(471)	**17 035**	16 287	16 141

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONT'D)

(a) A significant portion of activities in the Upstream 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	**2008**	2007	2006
Total external and intersegment sales	**4 766**	3 923	3 303
Total expenses	**3 002**	2 394	1 966
Net income, after income tax	**1 302**	1 224	1 148
Total current assets	**758**	1 043	516
Long-term assets	**5 380**	4 868	4 833
Total current liabilities	**659**	705	810
Other long-term obligations	**619**	460	344
Cash flow from operating activities	**1 891**	865	1 229
Cash (used in) investing activities	**(685)**	(131)	(403)

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

millions of dollars	**2008**	2007	2006
Upstream	**3 095**	2 013	1 936
Downstream	**1 685**	922	869
Chemical	**844**	768	793
Total export sales	**5 624**	3 703	3 598

(c) Consolidated selling and general expenses include delivery costs from final storage areas to customers of $314 million in 2008 (2007 – $318 million, 2006 – $316 million).

(d) Includes property, plant and equipment under construction of $1,523 million (2007 – $951 million).

(e) All goodwill has been assigned to the Downstream 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 (CONT'D)

4. Income taxes

millions of dollars	2008	2007	2006
Current income tax expense	**1 005**	1 163	776
Deferred income tax expense (a)	**393**	28	280
Total income tax expense (b)	**1 398**	1 191	1 056
Statutory corporate tax rate (percent)	**29.5**	30.1	32.8
Increase/(decrease) resulting from:			
Enacted tax rate change	**–**	(2.2)	(2.7)
Other	**(3.0)**	(0.7)	(4.3)
Effective income tax rate	**26.5**	27.2	25.8

(a) The provisions for deferred income taxes in 2008 include net (charges)/credits for the effect of changes in tax laws and rates of $1 million (2007 – $90 million, 2006 – $81 million).

(b) Cash outflow from income taxes, plus investment credits earned, was $1,101 million in 2008 (2007 – $1,395 million, 2006 – $1,000 million).

Income taxes (charged)/credited directly to shareholders' equity were:

millions of dollars	2008	2007	2006
Post-retirement benefits liability adjustment:			
Net actuarial loss/(gain)	**102**	21	
Amortization of net actuarial (loss)/gain	**(26)**	(24)	
Prior service cost	**–**	13	
Amortization of prior service cost	**(5)**	(6)	
Total post-retirement benefits liability adjustment	**71**	4	212
Minimum pension liability adjustment	**–**	–	(146)

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	2008	2007	2006
Depreciation and amortization	**1 685**	1 624	1 588
Successful drilling and land acquisitions	**258**	276	263
Pension and benefits	**(312)**	(249)	(311)
Site restoration	**(202)**	(156)	(161)
Net tax loss carryforwards (a)	**(2)**	(37)	(42)
Capitalized interest	**53**	49	50
Other	**9**	(36)	(42)
Deferred income tax liabilities	**1 489**	1 471	1 345
LIFO inventory valuation	**(301)**	(547)	(448)
Other	**(60)**	(113)	(125)
Deferred income tax assets	**(361)**	(660)	(573)
Valuation allowance	**–**	–	–
Net deferred income tax liabilities	**1 128**	811	772

(a) Tax losses can be carried forward indefinitely.

Unrecognized tax benefits

As of January 1, 2007, the company adopted the Financial Accounting Standards Board (FASB) Interpretation No. 48 (FIN 48), "Accounting for Uncertainty in Income Taxes". The cumulative adjustment for the accounting change reported in 2007 was an after-tax gain of $14 million. The gain reflected the recognition of several refund claims with associated interest, partly offset by increased income tax reserves.

Unrecognized tax benefits reflect the difference between positions taken on tax returns and the amounts recognized in the financial statements. Resolution of the related tax positions will take many years to complete. It is difficult to predict the timing of resolution for individual tax positions, since such timing is not entirely within the control of the company. The company's effective tax rate will be reduced if any of these tax benefits are subsequently recognized.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONT'D)

The following table summarizes the movement in unrecognized tax benefits:

millions of dollars	**2008**	2007
January 1 balance	**170**	142
Additions for prior years' tax positions	**9**	28
Reductions for prior years' tax positions	**(29)**	–
December 31 balance	**150**	170

The 2008 and 2007 changes in unrecognized tax benefits did not have a material effect on the company's net income or cash flow. The company's tax filings from 2004 to 2007 are subject to examination by the tax authorities. The Canada Revenue Agency has proposed certain adjustments to the company's filings for several years in the period 1994 to 2003. Management is currently evaluating those proposed adjustments. Management believes that a number of outstanding matters before 2004 are expected to be resolved in 2009. The impact on unrecognized tax benefits and the company's effective income tax rate from these matters is not expected to be material.

The company classifies interest on income tax related balances as interest expense or interest income and classifies tax related penalties as operating expense.

5. 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 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 obligation and pension expense can vary significantly with changes in the assumptions used to estimate the obligation and the expected return on plan assets.

The benefit obligations and plan assets associated with the company's defined benefit plans are measured on December 31.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONT'D)

	Pension benefits		Other post-retirement benefits	
	2008	2007	**2008**	2007
Assumptions used to determine benefit obligations at December 31 (percent)				
Discount rate	**7.50**	5.75	**7.50**	5.75
Long-term rate of compensation increase	**4.50**	3.50	**4.50**	3.50

millions of dollars				
Change in projected benefit obligation				
Projected benefit obligation at January 1	**4 685**	4 716	**426**	441
Current service cost	**94**	100	**6**	6
Interest cost	**271**	246	**25**	23
Amendments	**–**	41	**–**	–
Actuarial loss/(gain)	**(583)**	(131)	**(61)**	(25)
Benefits paid (a)	**(331)**	(287)	**(24)**	(19)
Projected benefit obligation at December 31	**4 136**	4 685	**372**	426
Accumulated benefit obligation at December 31	**3 719**	4 208		
Change in plan assets				
Fair value at January 1	**4 098**	4 089		
Actual return/(loss) on plan assets	**(699)**	93		
Company contributions	**165**	163		
Benefits paid (b)	**(252)**	(247)		
Fair value at December 31	**3 312**	4 098		
Plan assets in excess of/(less than) projected benefit obligation at December 31				
Funded plans	**(488)**	(213)	**–**	–
Unfunded plans	**(336)**	(374)	**(372)**	(426)
Total (c)	**(824)**	(587)	**(372)**	(426)

(a) Benefit payments for funded and unfunded plans.
(b) Benefit payments for funded plans only.
(c) Fair value of assets less projected benefit obligation shown above.

Effective December 31, 2006, the company adopted Statement of Financial Accounting Standards No. 158 (SFAS 158), "Employers' Accounting for Defined Benefit Pension and Other Post-retirement Plans, an amendment to FASB Statements No. 87, 88, 106 and 132(R)", which requires an employer to recognize the overfunded or underfunded status of a defined benefit post-retirement plan as an asset or liability in its balance sheet and to recognize changes in that funded status in the year in which the changes occur through other comprehensive income.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONT'D)

millions of dollars	Pension benefits 2008	2007	2006	Other post-retirement benefits 2008	2007	2006
Amounts recorded in the consolidated balance sheet consist of:						
Current liabilities	**(22)**	(34)		**(23)**	(25)	
Other long-term obligations	**(802)**	(553)		**(349)**	(401)	
Total recorded	**(824)**	(587)		**(372)**	(426)	
Amounts recorded in accumulated other comprehensive income consist of:						
Net actuarial loss/(gain)	**1 331**	977		**(25)**	42	
Prior service cost	**77**	95		**–**	–	
Total recorded in accumulated other comprehensive income, before tax	**1 408**	1 072		**(25)**	42	
Assumptions used to determine net periodic benefit cost for years ended December 31 (percent)						
Discount rate	**5.75**	5.25	5.00	**5.75**	5.25	5.00
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	**8.00**	8.00	8.25	**–**	–	–

millions of dollars	Pension benefits 2008	2007	2006	Other post-retirement benefits 2008	2007	2006
Components of net periodic benefit cost						
Current service cost	**94**	100	100	**6**	6	8
Interest cost	**271**	246	238	**25**	23	23
Expected return on plan assets	**(330)**	(329)	(299)	**–**	–	–
Amortization of prior service cost	**19**	20	20	**–**	–	–
Recognized actuarial loss/(gain)	**91**	76	114	**6**	6	8
Net periodic benefit cost	**145**	113	173	**37**	35	39
Changes in amounts recorded in accumulated other comprehensive income						
Net actuarial loss/(gain)	**446**	105	72	**(61)**	(25)	73
Amortization of net actuarial (loss)/gain included in net periodic benefit cost	**(91)**	(76)	–	**(5)**	(6)	–
Prior service cost	**–**	41	74	**–**	–	–
Amortization of prior service cost included in net periodic benefit cost	**(19)**	(20)	–	**–**	–	–
Total recorded in accumulated other comprehensive income	**336**	50	146	**(66)**	(31)	73
Total recorded in net periodic benefit cost and accumulated other comprehensive income, before tax	**481**	163	319	**(29)**	4	112

Costs for defined contribution plans, primarily the employee savings plan, were $33 million in 2008 (2007 – $31 million, 2006 – $30 million).

A summary of the change in accumulated other comprehensive income is shown in the table below:

millions of dollars	Total pension and other post-retirement benefits 2008	2007	2006
(Charge)/credit to accumulated other comprehensive income, before tax	**(270)**	(19)	(219)
Deferred income tax (charge)/credit (note 4)	**71**	4	66
(Charge)/credit to accumulated other comprehensive income, after tax	**(199)**	(15)	(153)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONT'D)

The preceding data in this note conform with current accounting standards that specify use of a discount rate at which post-retirement liabilities could be effectively settled. The discount rate for calculating year-end post-retirement liabilities is based on the yield for high quality, long-term Canadian corporate bonds at year-end with an average maturity (or duration) approximately that of the liabilities. The measurement of the accumulated post-retirement benefit obligation assumes a health care cost trend rate of 6.50 percent in 2009 that declines to 4.50 percent by 2011.

The company establishes the long-term expected rate of return on plan assets 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 2008 long-term expected return of 8.00 percent used in the calculations of pension expense compares to an actual rate of return of 5.00 percent and 8.31 percent over the last 10- and 20-year periods ending December 31, 2008.

The company's pension plan asset allocation at December 31, 2007 and 2008, and target allocation for 2009 are as follows:

	Target allocation	Percentage of plan assets at December 31	
Asset category (percent)	2009	**2008**	2007
Equity securities	50-75	**63**	61
Debt securities	25-50	**36**	38
Other	0-10	**1**	1

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.

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

	Pension benefits	
millions of dollars	**2008**	2007
For funded pension plans with accumulated benefit obligations in excess of plan assets:		
Projected benefit obligation	**3 800**	398
Accumulated benefit obligation	**3 420**	318
Fair value of plan assets	**3 312**	254
Accumulated benefit obligation less fair value of plan assets	**108**	64
For unfunded plans covered by book reserves:		
Projected benefit obligation	**336**	373
Accumulated benefit obligation	**299**	347

Estimated 2009 amortization from accumulated other comprehensive income

millions of dollars	Pension benefits	Other post-retirement benefits
Net actuarial loss/(gain) (a)	110	(1)
Prior service cost (b)	17	–

(a) The company amortizes the net balance of actuarial loss/(gain) over the average remaining service period of active plan participants.
(b) The company amortizes prior service cost on a straight-line basis as permitted under SFAS 87 and SFAS 106.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONT'D)

Cash flows
Benefit payments expected in:

millions of dollars	Pension benefits	Other post-retirement benefits
2009	274	25
2010	277	25
2011	282	25
2012	288	25
2013	296	25
2014 – 2018	1 623	128

In 2009, the company expects to make cash contributions of about $200 million to its pension plans.

Sensitivities
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 cost, before tax	(40)	40
Discount rate:		
Effect on net benefit cost, before tax	(55)	65
Effect on benefit obligation	(440)	530
Rate of pay increases:		
Effect on net benefit cost, before tax	35	(30)
Effect on benefit obligation	115	(105)

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 benefit obligation	31	(26)

6. Other long-term obligations

millions of dollars	**2008**	2007
Employee retirement benefits (note 5) (a)	**1 151**	954
Asset retirement obligations and other environmental liabilities (b)	**728**	522
Share-based incentive compensation liabilities (note 8)	**203**	210
Other obligations	**216**	228
Total other long-term obligations	**2 298**	1 914

(a) Total recorded employee retirement benefit obligations also include $45 million in current liabilities (2007 – $59 million).
(b) Total asset retirement obligations and other environmental liabilities also include $83 million in current liabilities (2007 – $74 million). The following table summarizes the activity in the liability for asset retirement obligations:

millions of dollars	**2008**	2007
January 1 balance	**488**	422
Additions	**232**	71
Accretion	**29**	25
Settlement	**(38)**	(30)
December 31 balance	**711**	488

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONT'D)

7. Derivatives and financial instruments

The company did not enter into any energy derivatives, foreign-exchange forward contracts or currency and interest-rate swaps 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 and the recorded book value.

8. Share-based incentive compensation programs

Share-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, as adjusted for any share splits. 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 ten 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, as adjusted for any share splits.

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, as adjusted for any share splits.

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 five-day average of the closing price of the company's common shares on the Toronto Stock Exchange on and immediately prior to 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. The company may also issue units where fifty percent of the units are exercisable five years following the grant date and the remainder are exercisable on the later of ten years following the grant date or the retirement date of the recipient. For units granted in 2002 to 2005, the exercise date has been changed from December 31 to December 4 for units exercised in 2006 and subsequent years. For units granted in 2002, 2003, 2004 and 2005 to be exercised subsequent to the company's May 2006 three-for-one share split, the company has indicated that it will increase the cash payment or number of shares issued per unit, as the case may be, by a factor of three.

All units require settlement by cash payments with the following exceptions. The restricted stock unit program was amended for units granted in 2002 and subsequent 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 in the seventh year following the grant date. For units where fifty percent are exercisable five years following the grant date and the remainder exercisable on the later of ten years following the grant date or the retirement date of the recipient, the recipient may receive one common share of the company per unit or elect to receive cash payment for all units to be exercised.

The company accounts for these units by using the fair-value-based method. The fair value of awards in the form of incentive share, deferred share and restricted stock units is the market price of the company's stock. Under this method, compensation expense related to the units of these programs is measured each reporting period based on the company's current stock price and is recorded in the consolidated statement of income over the requisite service period of each award.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONT'D)

The following table summarizes information about these units for the year ended December 31, 2008:

	Incentive share units	Deferred share units	Restricted stock units
Outstanding at January 1, 2008	**6 758 850**	**90 526**	**10 219 851**
Granted	**–**	**10 937**	**1 760 795**
Exercised	**(1 249 335)**	**(15 092)**	**(1 328 233)**
Cancelled or adjusted	**1 500**	**–**	**(55 850)**
Outstanding at December 31, 2008	**5 511 015**	**86 371**	**10 596 563**

There was a $33 million favourable adjustment to previously recorded compensation expenses for these programs in the year ended December 31, 2008. The compensation expense charged against income for these programs was $202 million and $133 million for the years ended December 31, 2007 and 2006, respectively. Income tax expense associated with the favourable adjustment to compensation expense for the year ended December 31, 2008 was $5 million, and the income tax benefit recognized in income related to compensation expense for these programs was $67 million and $45 million for the years ended December 31, 2007 and 2006, respectively. Cash payments of $115 million, $159 million and $162 million for these programs were made in 2008, 2007 and 2006, respectively.

As of December 31, 2008, there was $201 million of total before-tax unrecognized compensation expense related to nonvested restricted stock units based on the company's share price at the end of the current reporting period. The weighted average vesting period of nonvested restricted stock units is 3.9 years. All units under the incentive share and deferred share programs have vested as of December 31, 2008.

Incentive stock options

In April 2002, incentive stock options were granted for the purchase of the company's common shares. For units exercised subsequent to the company's May 2006 three-for-one split, the company has indicated that it will give the option holders the right to purchase three shares for each original stock option granted. The exercise price is $15.50 per share (adjusted to reflect the three-for-one share split). All options have vested as of December 31, 2008. 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.

As permitted by SFAS 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.

No compensation expense and no income tax benefit related to stock options were recognized for stock options in the years ended December 31, 2008, 2007 and 2006. The aggregate intrinsic value of stock options exercised was $17 million, $25 million and $18 million in the years ended December 31, 2008, 2007 and 2006, respectively, and for the balance of outstanding stock options is $109 million as at December 31, 2008.

The average fair value of each option granted during 2002 was $4.23 (adjusted to reflect the three-for-one share split). 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. Purchase may be discontinued at any time without prior notice.

The following table summarizes information about stock options for the year ended December 31, 2008:

	2008		
	Units	Exercise price (dollars)	Remaining contractual term (years)
Incentive stock options			
Outstanding at January 1	**4 728 780**	**15.50**	
Granted	–		
Exercised	**(434 145)**	**15.50**	
Cancelled or adjusted	**–**		
Outstanding at December 31	**4 294 635**	**15.50**	**3.3**

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONT'D)

9. Investment and other income

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

millions of dollars	**2008**	2007	2006
Proceeds from asset sales	**272**	279	212
Book value of assets sold	**31**	64	78
Gain/(loss) on asset sales, before tax (a) (b)	**241**	215	134
Gain/(loss) on asset sales, after tax (a) (b)	**209**	156	96

(a) 2007 included a gain of $200 million ($142 million, after tax) from the sale of the company's interests in a natural gas producing property in British Columbia and in the Willesden Green producing property.
(b) 2008 included a gain of $219 million ($187 million, after tax) from the sale of the company's equity investment in Rainbow Pipe Line Co. Ltd.

10. Litigation and other contingencies

A variety of claims have been made against Imperial Oil Limited and its subsidiaries in a number of lawsuits. Management has regular litigation reviews, including updates from corporate and outside counsel, to assess the need for accounting recognition or disclosure of these contingencies. The company accrues an undiscounted liability for those contingencies where the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. The company does not record liabilities when the likelihood that the liability has been incurred is probable but the amount cannot be reasonably estimated or when the liability is believed to be only reasonably possible or remote. For contingencies where an unfavourable outcome is reasonably possible and which are significant, the company discloses the nature of the contingency and, where feasible, an estimate of the possible loss. 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.

The Alberta government enacted changes to the oil and gas and generic oil sands royalty regime effective 2009. The impacts of the changes have been incorporated in the company's 2008 oil and gas reserves and mined bitumen reserves calculation, where appropriate. In November 2008, Imperial, along with the other Syncrude joint-venture owners, signed an agreement with the Government of Alberta to amend the existing Syncrude Crown Agreement. Under the amended agreement, beginning January 1, 2010, Syncrude will begin transitioning to the new oil sands royalty regime by paying additional royalties, the exact amount of which will depend on production levels from 2010 to 2015. Also, beginning January 1, 2009, Syncrude's royalty will be based on bitumen value with upgrading costs and revenues excluded from the calculation. The impacts of the amended agreement have been incorporated in the 2008 synthetic crude oil reserves calculation.

The company was contingently liable at December 31, 2008 for a maximum of $79 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.

Additionally, the company has other commitments arising in the normal course of business for operating and capital needs, all of which are expected to be fulfilled with no adverse consequences material to the company's operations or financial condition. Unconditional purchase obligations, as defined by accounting standards, are those long-term commitments that are non-cancelable or cancelable only under certain conditions and that third parties have used to secure financing for the facilities that will provide the contracted goods and services.

	Payments due by period						
millions of dollars	2009	2010	2011	2012	2013	After 2013	Total
Unconditional purchase obligations (a)	**127**	**63**	**74**	**43**	**82**	**31**	**420**

(a) Undiscounted obligations of $420 million mainly pertain to pipeline throughput agreements. Total payments under unconditional purchase obligations were $117 million (2007 – $94 million, 2006 – $100 million). The present value of these commitments, excluding imputed interest of $66 million, totaled $354 million.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONT'D)

11. Common shares

thousands of shares	**As at Dec. 31 2008**	As at Dec. 31 2007
Authorized	**1 100 000**	1 100 000

From 1995 to 2007, the company purchased shares under twelve 12-month normal course share purchase programs, as well as an auction tender. On June 25, 2008, a 12-month share repurchase program was implemented with an allowable purchase of about 44 million shares (five percent of the total at June 16, 2008), less shares purchased from Exxon Mobil Corporation and shares purchased by the employee savings plan and company pension fund. The results of these activities are shown below.

Year	Purchased shares (thousands)	Millions of dollars
1995 to 2006	795 623	10 453
2007	50 516	2 358
2008	**44 295**	**2 210**
Cumulative purchases to date	890 434	15 021

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

The excess of the purchase cost over the stated value of shares purchased has been recorded as a distribution of earnings reinvested.

The company's common share activities are summarized below:

	Thousands of shares	Millions of dollars
Balance as at January 1, 2006	997 875	1 747
Issued for cash under the stock option plan	627	10
Purchases at stated value	(45 514)	(80)
Balance as at December 31, 2006	952 988	1 677
Issued for cash under the stock option plan	791	12
Purchases at stated value	(50 516)	(89)
Balance as at December 31, 2007	903 263	1 600
Issued for cash under the stock option plan	**434**	**7**
Purchases at stated value	**(44 295)**	**(79)**
Balance as at December 31, 2008	**859 402**	**1 528**

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONT'D)

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

	2008	2007	2006
Net income per common share – basic			
Net income (millions of dollars)	**3 878**	3 188	3 044
Weighted average number of common shares outstanding (thousands of shares)	**882 604**	928 527	975 128
Net income per common share (dollars)	**4.39**	3.43	3.12
Net income per common share – diluted			
Net income (millions of dollars)	**3 878**	3 188	3 044
Weighted average number of common shares outstanding (thousands of shares)	**882 604**	928 527	975 128
Effect of employee share-based awards (thousands of shares)	**6 418**	5 811	4 460
Weighted average number of common shares outstanding, assuming dilution (thousands of shares)	**889 022**	934 338	979 588
Net income per common share (dollars)	**4.36**	3.41	3.11

12. Miscellaneous financial information

In 2008, net income included an after-tax gain of $27 million (2007 – $25 million gain, 2006 – $14 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, 2008 by $994 million (2007 – $1,953 million). Inventories of crude oil and products at year-end consisted of the following:

millions of dollars	**2008**	2007
Crude oil	**328**	211
Petroleum products	**268**	298
Chemical products	**65**	43
Natural gas and other	**12**	14
Total inventories of crude oil and products	**673**	566

Research and development costs in 2008 were $83 million (2007 – $89 million, 2006 – $73 million) before investment tax credits earned on these expenditures of $9 million (2007 – $9 million, 2006 – $7 million). Research and development costs are included in expenses due to the uncertainty of future benefits.

Cash flow from operating activities included dividends of $11 million received from equity investments in 2008 (2007 – $22 million, 2006 – $18 million).

13. Financing costs

millions of dollars	**2008**	2007	2006
Debt-related interest	**8**	62	63
Capitalized interest	**(8)**	(36)	(48)
Net interest expense	**–**	26	15
Other interest	**–**	10	13
Total financing costs (a)	**–**	36	28

(a) Cash interest payments in 2008 were $6 million (2007 – $80 million, 2006 – $71 million). The weighted average interest rate on short-term borrowings in 2008 was 3.5 percent (2007 – 5.1 percent).

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONT'D)

14. Leased facilities and capitalized lease obligations

At December 31, 2008, the company held non-cancelable operating leases covering office buildings, rail cars, service stations and other properties with minimum undiscounted lease commitments totaling $432 million as indicated in the following table:

	Payments due by period						
millions of dollars	2009	2010	2011	2012	2013	After 2013	Total
Lease payments under minimum commitments (a)	**64**	**53**	**55**	**53**	**49**	**158**	**432**

(a) Total rental expense incurred for operating leases in 2008 was $149 million (2007 – $98 million, 2006 – $101 million) which included minimum rental expenditures of $140 million (2007 – $86 million, 2006 – $88 million). Related rental income was not material.

Capitalized lease 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 11.0 percent in 2008 (2007 – 10.9 percent). Total capitalized lease obligations also include $4 million in current liabilities (2007 – $4 million).

Principal payments on capital leases of approximately $4 million a year are due in each of the next five years.

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, natural gas, 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 upstream activities conducted jointly in Canada.

The company has existing agreements with ExxonMobil to:

(a) 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;

(b) operate the Western Canada production properties owned by ExxonMobil. This contractual agreement is designed to provide organizational efficiencies and to reduce costs. No separate legal entities were created from this arrangement. Separate books of account continue to be maintained for the company and ExxonMobil. The company and ExxonMobil retain ownership of their respective assets, and there is no impact on operations or reserves;

(c) provide for the delivery of management, business and technical services to Syncrude Canada Ltd. by ExxonMobil;

(d) share new upstream opportunities on an up to equal basis.

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

As at December 31, 2008, the company had outstanding loans of $35 million (2007 – $33 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.

SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES (unaudited)

Pages 60 to 63 provide information about the Upstream segment in accordance with Statement of Financial Accounting Standards No. 69 (SFAS 69), "Disclosures about oil and gas production activities". As such, the information on pages 60 and 61 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 and a 70.96 percent interest in proven mined bitumen reserves in the Kearl project. For internal management purposes, the company views these reserves and their development as an integral part of its total Upstream operations. However, for financial reporting purposes, these reserves are required to be reported separately from the oil and gas reserves as shown on page 62.

The synthetic crude oil and mined bitumen reserves are not considered in the standardized measure of discounted future cash flows for oil and gas reserves on page 61. The company's share of Syncrude and Kearl results of operations, capital and exploration expenditures and property, plant and equipment are also excluded from the following tables on this page.

Results of operations

	Oil and gas		
millions of dollars	**2008**	2007	2006
Sales to customers (a)	**3 343**	2 383	2 601
Intersegment sales (a) (b)	**1 297**	1 131	1 251
	4 640	3 514	3 852
Production expenses	**1 335**	1 074	1 016
Exploration expenses	**122**	100	32
Depreciation and depletion	**337**	371	467
Income taxes	**814**	526	564
Results of operations	**2 032**	1 443	1 773

Capital and exploration expenditures

	2008	2007	2006
Property costs (c)			
Proved	**–**	–	–
Unproved	**–**	1	–
Exploration costs	**122**	100	32
Development costs	**525**	437	496
Total capital and exploration expenditures	**647**	538	528

Property, plant and equipment

	2008	2007
Property costs (c)		
Proved	**3 168**	3 167
Unproved	**271**	148
Producing assets	**7 212**	6 706
Support facilities	**181**	180
Incomplete construction	**691**	579
Total cost	**11 523**	10 780
Accumulated depreciation and depletion	**7 840**	7 505
Net property, plant and equipment	**3 683**	3 275

(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 3 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.

SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES (unaudited) (CONT'D)

Standardized measure of discounted future cash flows
As required by SFAS 69, 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 remediation 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 and Kearl.

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

	Oil and gas		
millions of dollars	**2008**	2007	2006
Future cash flows	**18 956**	32 415	36 751
Future production costs	**(13 558)**	(14 475)	(16 290)
Future development costs	**(4 642)**	(3 548)	(2 633)
Future income taxes	**(111)**	(3 655)	(5 039)
Future net cash flows	**645**	10 737	12 789
Annual discount of 10 percent for estimated timing of cash flows	**613**	(4 487)	(6 374)
Discounted future cash flows	**1 258**	6 250	6 415

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

Balance at beginning of year	**6 250**	6 415	4 314
Changes resulting from:			
Sales and transfers of oil and gas produced, net of production costs	**(3 422)**	(2 430)	(2 839)
Net changes in prices, development costs and production costs	**(6 016)**	(625)	4 221
Extensions, discoveries, additions and improved recovery, less related costs	**25**	164	(4)
Development costs incurred during the year	**438**	412	411
Revisions of previous quantity estimates	**1 460**	1 285	87
Accretion of discount	**689**	710	568
Net change in income taxes	**1 834**	319	(343)
Net change	**(4 992)**	(165)	2 101
Balance at end of year	**1 258**	6 250	6 415

SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES (unaudited) (CONT'D)

Net proved developed and undeveloped reserves (a)

	Crude oil and NGLs millions of barrels			Natural gas billions of cubic feet	Synthetic crude oil(c) millions of barrels	Mined bitumen(d) millions of barrels
	Conventional	Heavy oil (b)	Total			
Beginning of year 2006	83	551	634	747	738	–
Revisions	4	236	240	140	1	–
Improved recovery	–	–	–	–	–	–
(Sale)/purchase of reserves in place	(1)	–	(1)	(6)	–	–
Discoveries and extensions	–	–	–	10	–	–
Production	(15)	(46)	(61)	(181)	(21)	–
End of year 2006	71	741	812	710	718	–
Revisions	24	(27)	(3)	75	–	–
Improved recovery	–	6	6	1	–	–
(Sale)/purchase of reserves in place	(1)	–	(1)	(12)	–	–
Discoveries and extensions	–	44	44	8	–	–
Production	(12)	(47)	(59)	(147)	(24)	–
End of year 2007	82	717	799	635	694	–
Revisions	**(8)**	**(66)**	**(74)**	**45**	**63**	**807**
Improved recovery	**–**	**(1)**	**(1)**	**–**	**–**	**–**
(Sale)/purchase of reserves in place	**–**	**–**	**–**	**–**	**–**	**–**
Discoveries and extensions	**–**	**25**	**25**	**4**	**–**	**–**
Production	**(10)**	**(45)**	**(55)**	**(91)**	**(23)**	**–**
End of year 2008	**64**	**630**	**694**	**593**	**734**	**807**

(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.
(b) Heavy oil reserves typically are represented by crude oils with a viscosity of greater than 10,000 cP and recovered through enhanced thermal operations. Currently, the company's heavy oil reserves include reserves attributable to the commercial phases of Cold Lake production operations.
(c) The company's synthetic crude oil reserves include reserves attributable to the company's share of the Syncrude joint venture.
(d) The company's mined bitumen reserves include reserves attributable to the company's share of the Kearl oil sands project.

The information above describes changes during the years and balances of proved oil and gas and proven synthetic crude oil and mined bitumen reserves at year-end 2006, 2007 and 2008. 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 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.

SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES (unaudited) (CONT'D)

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. Estimates of mined bitumen reserves are based on detailed geological and engineering assessments of in-place crude bitumen volumes, the mining plan, demonstrated extraction recovery factors, planned operating capacity and operating approval limits.

The year-end oil and gas reserves volumes as well as the reserves change categories shown in the proved reserves tables are calculated using December 31 prices and costs. These reserves quantities are also used in calculating unit-of-production depreciation rates and in calculating the standardized measure of discounted net cash flow. We understand that the use of December 31 prices and costs is intended to provide a point in time measure to calculate reserves and to enhance comparability between companies. However, the use of year-end prices for reserves estimation introduces short-term price volatility into the process, which is inconsistent with the long-term nature of the upstream business, since annual adjustments are required based on prices occurring on a single day. As a result, the use of prices from a single date is not relevant to the investment decisions made by the company.

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 in year-end prices and costs that are used in the determination of reserves. This category can also include significant changes in either development strategy or production equipment/facility capacity. The quantities shown in the revisions category under heavy oil proved reserves in 2006 were due mainly to changes in year-end prices and costs that were used in the determination of reserves. 807 million barrels of mined bitumen reserves were added in 2008 in the revisions category, reflecting the company's share of reserves being developed in the first phase of the Kearl oil sands project.

Net proved reserves are determined by deducting the estimated future share of mineral owners or governments or both. For conventional crude oil and natural gas, net proved reserves are based on estimated future royalty rates as of the date the estimate is made incorporating the Alberta government's new oil and gas royalty regime. For Cold Lake and Kearl, net proved reserves are based on the company's best estimate of average royalty rates over the life of each project and incorporate the Alberta government's new oil sands royalty regime. For Syncrude, net proven reserves are based on the company's best estimate of average royalty rates over the life of the project and incorporate amendments to the Syncrude Crown Agreement. In all cases, actual future royalty rates may vary with production, price and costs.

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

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.

SHARE OWNERSHIP, TRADING AND PERFORMANCE

	2008	2007	2006	2005	2004
Share ownership					
Average number outstanding, weighted monthly (thousands)	**882 604**	928 527	975 128	1 024 119	1 070 502
Number of shares outstanding at December 31 (thousands)	**859 402**	903 263	952 988	997 875	1 047 960
Shares held in Canada at December 31 (percent)	**11.1**	12.1	13.0	13.8	14.6
Number of registered shareholders at December 31 (a)	**13 206**	13 108	13 561	14 096	14 953
Number of shareholders registered in Canada	**11 620**	11 450	11 844	12 331	13 088
Shares traded (thousands)	**477 574**	292 888	321 245	357 633	281 334
Share prices (dollars) (b)					
Toronto Stock Exchange					
High	**62.54**	56.26	45.20	45.79	24.55
Low	**28.79**	37.40	34.31	22.50	18.81
Close at December 31	**40.99**	54.62	42.93	38.47	23.72
NYSE Alternext (U.S. dollars)					
High	**63.08**	61.48	40.38	39.14	20.82
Low	**23.84**	31.87	29.99	18.27	14.11
Close at December 31	**33.72**	54.78	36.83	33.20	19.79
Net income per share (dollars)					
– basic	**4.39**	3.43	3.12	2.54	1.92
– diluted	**4.36**	3.41	3.11	2.53	1.91
Price ratios at December 31					
Share price to net earnings (c)	**9.4**	16.0	13.8	15.2	12.4
Dividends declared (d)					
Total (millions of dollars)	**334**	324	311	320	314
Per share (dollars)	**0.38**	0.35	0.32	0.31	0.29

(a) Exxon Mobil Corporation owns 69.6 percent of Imperial's shares.
(b) Share prices were obtained from stock exchange records, adjusted for the three-for-one share split in 2006. U.S. dollar share price presented is based on consolidated U.S. market data. The company's shares trade in the United States of America on the NYSE Alternext, formerly known as the American Stock Exchange.
(c) Closing share price at December 31 on the Toronto Stock Exchange, divided by net income per share – diluted.
(d) 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 $3.50 a share on December 22, 1971, and $5.10 on February 22, 1994. Both amounts are restated for the 1998 and 2006 three-for-one share splits.

Employees

	2008	2007	2006	2005	2004
Number of employees at December 31	**4 843**	4 785	4 869	5 096	6 083

QUARTERLY FINANCIAL AND STOCK TRADING DATA (a)

	2008	three months ended			2007	three months ended		
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	Mar. 31	June 30	Sept. 30	Dec. 31
Financial data (millions of dollars)								
Total revenues and other income	**7 263**	**8 859**	**9 515**	**5 942**	5 934	6 339	6 430	6 740
Total expenses	**6 298**	**7 276**	**7 558**	**5 171**	4 819	5 319	5 240	5 686
Income before income taxes	**965**	**1 583**	**1 957**	**771**	1 115	1 020	1 190	1 054
Income taxes	**284**	**435**	**568**	**111**	(341)	(308)	(374)	(168)
Net income	**681**	**1 148**	**1 389**	**660**	774	712	816	886
Segmented net income (millions of dollars)								
Upstream	**650**	**938**	**999**	**336**	563	460	607	739
Downstream	**30**	**239**	**270**	**257**	198	314	191	218
Chemical	**24**	**10**	**38**	**28**	28	22	24	23
Corporate and other	**(23)**	**(39)**	**82**	**39**	(15)	(84)	(6)	(94)
Net income	**681**	**1 148**	**1 389**	**660**	774	712	816	886
Per-share information (dollars)								
Net earnings – basic	**0.76**	**1.29**	**1.57**	**0.77**	0.82	0.76	0.88	0.97
Net earnings – diluted	**0.75**	**1.28**	**1.57**	**0.76**	0.81	0.76	0.88	0.96
Dividends (declared quarterly)	**0.09**	**0.09**	**0.10**	**0.10**	0.08	0.09	0.09	0.09
Share prices (dollars) (b)								
Toronto Stock Exchange								
High	**58.09**	**62.54**	**57.80**	**46.43**	43.75	54.70	51.90	56.26
Low	**45.80**	**52.41**	**41.60**	**28.79**	37.40	41.77	40.86	45.57
Close	**53.80**	**56.16**	**45.58**	**40.99**	42.80	49.59	49.29	54.62
NYSE Alternext (U.S. dollars)								
High	**58.91**	**63.08**	**56.89**	**43.66**	38.29	50.35	50.95	61.48
Low	**44.30**	**51.24**	**40.00**	**23.84**	31.87	36.90	37.99	46.43
Close	**52.26**	**55.07**	**42.60**	**33.72**	37.12	46.34	49.56	54.78
Shares traded (thousands) (c)	**98 531**	**101 826**	**129 650**	**147 567**	72 127	67 374	68 882	84 505

(a) Quarterly data has not been audited by the company's independent auditors.
(b) Imperial's shares are listed on the Toronto Stock Exchange. The company's shares also trade in the United States of America on the NYSE Alternext, formerly known as the American Stock Exchange. The symbol on these exchanges for Imperial's common shares is IMO. Share prices were obtained from stock exchange records. U.S. dollar share price presented is based on consolidated U.S. market data.
(c) The number of shares traded is based on transactions on the above stock exchanges.

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 Thursday, April 30, 2009, at 9:30 a.m. local time at the TELUS Convention Centre, South Building, Macleod Hall, 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, 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 Imperial's transfer agent, 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

Website: www.cibcmellon.com

United States resident shareholders may transfer their shares through BNY Mellon Shareowner Service.

BNY Mellon Shareowner Service
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
- 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: 403-237-2075

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

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

Design: Designwerke Inc.

Photography: Brodylo + Morrow, Kate Kunz Photography, Rich La Salle Photography, Images Studio Photographic Arts, Leonard Segall, Metcalfe Photography, Photography By Windjack, Dave Callis, Syncrude archives, WesternGeco

Printing: J.F. Moore Communications

Imperial Oil Limited Board of Directors from left to right,
Jack M. Mintz, Victor L. Young, Krystyna T. Hoeg, Bruce H. March, Sheelagh D. Whittaker, Roger Phillips, Paul A. Smith and Robert C. Olsen.

Board of Directors

Krystyna T. Hoeg
Retired president and chief executive officer
Corby Distilleries Limited
Toronto, Ontario

Bruce H. March
Chairman, president and chief executive officer
Imperial Oil Limited
Calgary, Alberta

Jack M. Mintz
Palmer Chair in Public Policy, University of Calgary
Calgary, Alberta

Robert C. Olsen
Executive vice-president
ExxonMobil Production Company
Houston, Texas

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

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

Sheelagh D. Whittaker
Corporate director
London, England

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

Other Officers

Randy L. Broiles
Senior vice-president, resources division

Sean R. Carleton
Controller

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

Audit committee
V.L. Young, *chair*
S.D. Whittaker, *vice-chair*
K.T. Hoeg
J.M. Mintz
R. Phillips

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

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S.D. Whittaker, *chair*
J.M. Mintz, *vice-chair*
K.T. Hoeg
R.C. Olsen
R. Phillips
V.L. Young

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J.M. Mintz, *chair*
K.T. Hoeg, *vice-chair*
R.C. Olsen
R. Phillips
S.D. Whittaker
V.L. Young

Imperial Oil Foundation
K.T. Hoeg, *chair*
R. Phillips, *vice-chair*
J.M. Mintz, *director*
P.A. Smith, *director*
S.D. Whittaker, *director*
V.L. Young, *director*

Imperial Oil

Syncrude has reclaimed more than 4,500 hectares, including this wetland in an area once part of an active oil sands mining operation.

Imperial Oil Limited
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Calgary, Alberta T2P 3M9