IMPERIAL OIL LTD
Form 10-K
February 28, 2007

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-K
ANNUAL REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE
SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2006 Commission file number: 0-12014

IMPERIAL OIL LIMITED
(Exact name of registrant as specified in its charter)

CANADA (State or other jurisdiction of incorporation or organization)	98-0017682 (I.R.S. Employer Identification No.)
237 FOURTH AVENUE S.W., CALGARY, AB, CANADA (Address of principal executive offices)	T2P 3M9 (Postal Code)

Registrant s telephone number, including area code:
1-800-567-3776

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	**Name of each exchange on which registered**
None	**None**

Securities registered pursuant to Section 12(g) of the Act:
Common Shares (without par value)

(Title of Class)

Indicate by check mark if the registrant is a well-known seasoned issuer (as defined in Rule 405 of the Securities Exchange Act of 1934).
Yes þ Noo

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934.
Yes o No þ

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes þ Noo

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.
Yes þ Noo

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer (see definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Securities Exchange Act of 1934).
Large accelerated filer þ Accelerated filero Non-accelerated filero

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12 b-2 of the Securities Exchange Act of 1934).

Yes o No þ

As of the last business day of the 2006 second fiscal quarter, the aggregate market value of the voting stock held by non-affiliates of the registrant was Canadian $12,075,765,770 based upon the reported last sale price of such stock on the Toronto Stock Exchange on that date.

The number of common shares outstanding, as of February 15, 2007, was 949,989,788.

All dollar amounts set forth in this report are in Canadian dollars, except where otherwise indicated.
Note that numbers may not add due to rounding.

The following table sets forth (i) the rates of exchange for the Canadian dollar, expressed in U.S. dollars, in effect at the end of each of the periods indicated, (ii) the average of exchange rates in effect on the last day of each month during such periods, and (iii) the high and low exchange rates during such periods, in each case based on the noon buying rate in New York City for wire transfers in Canadian dollars as certified for customs purposes by the Federal Reserve Bank of New York.

	2006	**2005**	**2004**	**2003**	**2002**
			(dollars)		
Rate at end of period	0.8582	0.8579	0.8310	0.7738	0.6329
Average rate during period	0.8844	0.8276	0.7702	0.7186	0.6368
High	0.9100	0.8690	0.8493	0.7738	0.6619
Low	0.8528	0.7872	0.7158	0.6349	0.6200

On February 15, 2007, the noon buying rate in New York City for wire transfers in Canadian dollars as certified for customs purposes by the Federal Reserve Bank of New York was $0.8590 U.S. = $1.00 Canadian.

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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.

PART I

Item 1. Business.

Imperial Oil Limited was incorporated under the laws of Canada in 1880 and was continued under the Canada Business Corporations Act (the CBCA) by certificate of continuance dated April 24, 1978. The head and principal office of the company is located at 237 Fourth Avenue S.W. Calgary, Alberta, Canada T2P 3M9; telephone 1-800-567-3776. Exxon Mobil Corporation owns approximately 69.6 percent of the outstanding shares of the company with the remaining shares being publicly held, with the majority of shareholders having Canadian addresses of record. In this report, unless the context otherwise indicates, reference to the company or Imperial includes Imperial Oil Limited and its subsidiaries.

The company is one of Canada s largest integrated oil companies. It is active in all phases of the petroleum industry in Canada, including the exploration for, and production and sale of, crude oil and natural gas. In Canada, it is one of the largest producers of crude oil and natural gas liquids and a major producer of natural gas, and the largest refiner and marketer of petroleum products. It is also a major supplier of petrochemicals.

Financial Information by Operating Segments (under U.S. GAAP)

	2006	**2005**	**2004**	**2003**	**2002**
			(millions of dollars)		
External sales (1) :					
Natural resources	$ 4,619	$ 4,702	$ 3,689	$ 3,390	$ 2,573
Petroleum products	18,527	21,793	17,503	14,710	13,362
Chemicals	1,359	1,302	1,216	994	955
Corporate and other					
	$ 24,505	$ 27,797	$ 22,408	$ 19,094	$ 16,890
Intersegment sales:					
Natural resources	$ 3,837	$ 3,487	$ 2,891	$ 2,224	$ 2,217
Petroleum products	2,256	2,224	1,666	1,294	1,038
Chemicals	345	363	293	238	209
Net income (2) :					
Natural resources	$ 2,376	$ 2,008	$ 1,517	$ 1,174	$ 1,052
Petroleum products	624	694	556	462	147
Chemicals	143	121	109	44	54
Corporate and other (3) /eliminations	(99)	(223)	(130)	25	(39)
	$ 3,044	$ 2,600	$ 2,052	$ 1,705	$ 1,214
Identifiable assets at December 31 (4) :					
Natural resources	$ 7,513	$ 7,289	$ 6,822	$ 6,397	$ 5,982
Petroleum products	6,450	6,257	5,509	5,225	5,034
Chemicals	504	500	490	433	417
Corporate and other/eliminations	1,674	1,536	1,206	282	570
	$ 16,141	$ 15,582	$ 14,027	$ 12,337	$ 12,003

Capital and exploration expenditures:					
Natural resources	$ 787	$ 937	$ 1,113	$ 1,007	$ 986
Petroleum products	361	478	283	478	589
Chemicals	13	19	15	41	25
Corporate and other	48	41	34	33	12
	$ 1,209	$ 1,475	$ 1,445	$ 1,559	$ 1,612

(1) Export sales are reported in note 3 to the consolidated financial statements on page F-9. Total external sales include $4,894 million for 2005, $3,584 million for 2004, $2,851 million for 2003 and $2,431 million for 2002 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. See note 1, Summary of significant Accounting Policies.

(2) These amounts are presented as if each segment

were a separate business entity and, accordingly, include the financial effect of transactions between the segments. Intersegment sales are made essentially at prevailing market prices.

(3) Includes primarily interest charges on the debt obligations of the company, interest income on investments, incentive compensation expenses, and intersegment consolidating adjustments.

(4) The identifiable assets in each operating segment represent the net book value of the tangible and intangible assets attributed to such segment. Net intangible assets representing unrecognized prior service costs associated with the recognition of the additional minimum pension liability

in 2005 and prior years have been reclassified from the operating segments to the corporate and other segment. Amounts reclassified into the corporate and other segment were $92 million for 2005, $97 million in 2004, $89 million for 2003 and $114 million in 2002. This change has no impact on total identifiable assets at December 31 of 2005 and prior years.

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The company s operations are conducted in three main segments: natural resources (upstream), petroleum products (downstream) and chemicals. Natural resources operations include the exploration for, and production of, conventional crude oil, natural gas, upgraded crude oil and heavy oil. Petroleum products operations consist of the transportation, refining and blending of crude oil and refined products and the distribution and marketing thereof. The chemicals operations consist of the manufacturing and marketing of various petrochemicals.

Natural Resources

Petroleum and Natural Gas Production

The company s average daily production of crude oil and natural gas liquids during the five years ended December 31, 2006, was as follows:

		2006	2005	2004	2003	2002
				(thousands a day)		
Conventional (including natural gas liquids):						
Cubic metres	Gross (1)	8.7	11.0	12.1	11.8	12.4
	Net (2)	6.7	8.6	9.4	9.1	9.5
Barrels	Gross (1)	55	69	76	74	78
	Net (2)	42	54	59	57	60
Heavy Oil (3):						
Cubic metres	Gross (1)	24.1	22.1	20.0	20.5	17.8
	Net (2)	20.1	19.7	17.7	18.4	16.9
Barrels	Gross (1)	152	139	126	129	112
	Net (2)	127	124	112	116	106
Oil Sands (4):						
Cubic metres	Gross (1)	10.3	8.4	9.5	8.4	9.1
	Net (2)	9.3	8.4	9.4	8.3	9.1
Barrels	Gross (1)	65	53	60	53	57
	Net (2)	58	53	59	52	57
Total:						
Cubic metres	Gross (1)	43.1	41.5	41.6	40.7	39.3
	Net (2)	36.1	36.7	36.5	35.8	35.5
Barrels	Gross (1)	272	261	262	256	247
	Net (2)	227	231	230	225	223

(1) Gross production of crude oil is the company s share of production from conventional wells, Syncrude oil sands and Cold Lake heavy oil, and gross production of natural gas liquids is the amount derived from processing

the company s share of production of natural gas (excluding purchased gas), in each case before deduction of the mineral owners or governments share or both.

(2) Net production is gross production less the mineral owners or governments share or both.

(3) Heavy oil typically is represented by crude oils with a viscosity of greater than 10,000 cP and recovered through enhanced thermal operations. The company s heavy oil production volumes are from the Cold Lake production operations.

(4) Oil sands are a semi-solid material composed of bitumen, sand, water and clays which are recovered through surface mining methods.

Imperial s oil sands production volumes are the company s share of production volumes in the Syncrude joint venture.

In 2003, conventional production declined mainly due to natural decline of the company s conventional oil fields. In 2004, conventional production increased primarily due to increased natural gas liquids production from the Wizard Lake gas cap. In 2005 and 2006 conventional production declined mainly due to the natural decline of the company s conventional fields. In 2003, Cold Lake net production increased as a result of a full year of production of phases 11 to 13, which was offset in part by the timing of steaming cycles and higher royalties. Syncrude production decreased in 2003 due to extended maintenance of upgrading facilities. In 2004, Cold Lake production declined due to the timing of steaming cycles and higher royalty, and Syncrude production increased due to fewer disruptions in upgrading operations than in 2003. In 2005, Cold Lake production increased due to the timing of steaming cycles and increased volumes from the ongoing development drilling program, and Syncrude production declined primarily due to greater maintenance downtime for upgrading facilities. In 2006, Cold Lake production increased due to timing of steam cycles and production from the ongoing development drilling program and Syncrude production increased due to lower maintenance activities and the start-up of expanded upgrading facilities.

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The company s average daily production and sales of natural gas during the five years ended December 31, 2006 are set forth below. All gas volumes in this report are calculated at a pressure base of, in the case of cubic metres, 101.325 kilopascals absolute at 15 degrees Celsius and, in the case of cubic feet, 14.73 pounds per square inch absolute at 60 degrees Fahrenheit.

	2006	2005	2004	2003	2002
			(millions a day)		
Sales (1) :					
Cubic metres	14.5	15.2	14.7	13.0	14.1
Cubic feet	513	536	520	460	499
Gross Production (2):					
Cubic metres	15.8	16.4	16.1	14.5	15.0
Cubic feet	556	580	569	513	530
Net Production (2):					
Cubic metres	14.1	14.6	14.7	12.9	13.1
Cubic feet	496	514	518	457	463

(1) Sales are sales of the company s share of production (before deduction of the mineral owners and/or governments share) and sales of gas purchased, processed and/or resold.

(2) Gross production of natural gas is the company s share of production (excluding purchases) before deducting the shares of mineral owners or governments or both. Net production excludes those shares.

Production data include amounts used for internal consumption with the exception of amounts reinjected.

In 2003, natural gas production decreased primarily due to the depletion of gas caps in Alberta and increased maintenance activity at gas processing facilities. In 2004 natural gas production increased primarily due to increased production from the Wizard Lake gas cap. In 2005, gross natural gas production increased due to increased production from the Nisku and Wizard Lake gas caps and the Medicine Hat gas field. In 2006, gas production decreased primarily due to natural decline.

Most of the company s natural gas sales are made under short term contracts.

The company s average sales price and production costs for crude oil and natural gas liquids and natural gas for the five years ended December 31, 2006, were as follows:

	2006	2005	2004	2003	2002
Average Sales Price:					
Crude oil and natural gas liquids:					
Per cubic metre	$ 283.84	$ 234.04	$ 207.26	$ 181.92	$ 174.72
Per barrel	45.13	37.21	32.95	28.92	27.78
Natural gas:					
Per thousand cubic metres	$ 255.58	$ 317.71	$ 239.34	$ 232.99	$ 141.91
Per thousand cubic feet	7.24	9.00	6.78	6.60	4.02
Average Production Costs Per Unit of Net Production (1),(2):					
Per cubic metre	$ 69.69	$ 67.82	$ 58.16	$ 60.78	$ 53.09
Per barrel	11.08	10.78	9.25	9.66	8.44

(1) Average production costs per unit of production do not include depreciation and depletion of capitalized acquisition, exploration and development costs. Administrative expenses are included. Average production (lifting) costs per unit of net

production were computed after converting gas production into equivalent units of oil on the basis of relative energy content.

(2) Unit production costs are sometimes referred to as lifting costs.

Canadian crude oil prices are mainly determined by international crude oil markets which are volatile.

Canadian natural gas prices are determined by North American gas markets and are also volatile. Natural gas prices throughout North America increased in the second half of 2005 due to supply disruptions from hurricane damage to facilities in the U.S. Gulf Coast.

In 2003 and 2005, average unit production costs increased mainly due to higher costs of purchased natural gas at Cold Lake. In 2004, average unit production costs decreased mainly due to higher production from the Wizard Lake gas cap. In 2006, average production costs increased due to lower gas production and higher liquids royalties resulting in lower net liquids production. Liquids royalties were higher in the year due to increased realizations for Cold Lake production.

The company has interests in a large number of facilities related to the production of crude oil and natural gas. Among these facilities are 22 plants that process natural gas to produce marketable gas and recover natural gas liquids or sulphur. The company is the principal owner and operator of 11 of the plants.

The company s production of conventional crude oil, Cold Lake heavy oil and natural gas is derived from wells located exclusively in Canada. The total number of producing wells in which the company had interests at

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December 31, 2006, is set forth in the following table. The statistics in the table are determined in part from information received from other operators.

	Crude Oil		Natural Gas		Total	
	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)
Conventional wells	1,241	794	4,791	2,612	6,032	3,406
Heavy Oil wells	3,983	3,983			3,983	3,983

(1) Gross wells are wells in which the company owns a working interest.

(2) Net wells are the sum of the fractional working interests owned by the company in gross wells, rounded to the nearest whole number.

Conventional Oil and Gas

The company s largest conventional oil producing asset is the Norman Wells oil field in the Northwest Territories which currently accounts for approximately 55 percent of the company s net production of conventional crude oil (approximately 61 percent of gross production). In 2006, net production of crude oil and natural gas liquids was about 2,000 cubic metres (12,700 barrels) per day and gross production was about 3,000 cubic metres (18,900 barrels) per day. The Government of Canada has a one-third carried interest and receives a production royalty of five percent in the Norman Wells oil field. The Government of Canada s carried interest entitles it to receive payment of a one-third share of an amount based on revenues from the sale of Norman Wells production, net of operating and capital costs. Under a shipping agreement, the company pays for the construction, operating and other costs of the 870 kilometre (540 mile) pipeline which transports the crude oil and natural gas liquids from the project. In 2006, those costs were about $33 million.

Most of the larger oil fields in the Western Provinces have been in production for several decades, and the amount of oil that is produced from conventional fields is declining. In some cases, however, additional oil can be recovered by using various methods of enhanced recovery. The company s largest enhanced recovery projects are located at the West Pembina oil field.

The company produces natural gas from a large number of gas fields located in the Western Provinces, primarily in Alberta. The company also has a nine percent interest in a project to develop and produce natural gas reserves in the Sable Island area off the coast of the Province of Nova Scotia.

Cold Lake

The company holds about 78,000 hectares (192,000 acres) of heavy oil leases near Cold Lake, Alberta. To develop the technology necessary to produce this oil commercially, the company has conducted experimental pilot operations since 1964 to recover the heavy oil from wells by means of new drilling and production techniques including steam injection. Research at, and operation of, the Cold Lake pilots is continuing.

In late 1983, the company commenced the development, in phases, of its heavy oil resources at Cold Lake. During 2006, average net production at Cold Lake was about 20,100 cubic metres (126,700 barrels) per day and gross production was about 24,100 cubic metres (151,800 barrels) per day.

To maintain production at Cold Lake, capital expenditures for additional production wells and associated facilities will be required periodically. In 2006, the company spent $213 million and executed a development drilling program of 174 wells on existing phases. In 2007, a development drilling program of more than 100 wells is planned within the currently approved development area to add productive capacity from undeveloped areas of existing Cold Lake phases. In addition, opportunities are also being evaluated to improve utilization of the existing infrastructure.

In 2004, the company received regulatory approval for further expansion of its operations at Cold Lake. Production began in 2006 from part of the approved expansion, the development of which is expected to cost about $400 million and is expected to have gross production of about 4,800 cubic metres (30,000 barrels) per day by the end of the decade. Development plans for the remainder of the approved expansion are being examined to reduce development costs through increased integration with existing infrastructure. Most of the production from Cold Lake is sold to refineries in the northern United States. The remainder of the Cold Lake production is shipped to certain of the company s refineries and to a heavy oil upgrader in Lloydminster, Saskatchewan.

The Province of Alberta, in its capacity as lessor of the Cold Lake heavy oil leases, is entitled to a royalty on production from the Cold Lake production project. The royalty agreement which applied through the end of 1999, provided for a royalty calculated at the greater of five percent of gross revenue or 30 percent of an amount based on revenue net of operating and capital costs. It also provided for a royalty waiver on equity natural gas produced in Alberta and deemed to be consumed in generating steam at the company s Cold Lake operations. In late 2000, the company entered into an agreement with the Province of Alberta, effective January 1, 2000, on a transitional royalty arrangement that will apply to all of the company s current and proposed operations at Cold Lake until the end of 2007, at which time the generic Alberta regulations for heavy oil royalties will apply. The post-transition royalty regulation, which will become effective in 2008, provides for a royalty calculated at the greater of one

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percent of gross revenue or 25 percent of an amount based on revenue net of operating and capital costs, but with no gas royalty waiver. The transition agreement, which is effective between 2000 and 2007 inclusive, makes provision for the differences between the two royalty regimes (higher bitumen royalties with gas royalty waiver vs. lower bitumen royalties and no gas royalty waiver). This transition will bring all phases of the company s Cold Lake operations under one royalty agreement with common terms and conditions. The transition is not expected to materially change the amount of royalties that the company would have otherwise paid under the pre-existing royalty arrangements. The effective royalty on gross production was 17 percent in 2006, 11 percent in 2005 and 2004, 10 percent in 2003 and five percent in 2002.

Other Heavy Oil Activity

The company has interests in other heavy oil leases in the Athabasca and Peace River areas of northern Alberta. Evaluation wells completed on these leased areas established the presence of heavy oil. The company continues to evaluate these leases to determine their potential for future development.

The company holds varying interests in heavy oil lands totalling about 68,000 leased net hectares (168,000 net acres) in the Athabasca area. The company, as part of an industry consortium and several joint ventures, has been involved in recovery research and pilot studies and in evaluating the quality and extent of the heavy oil deposit.

Syncrude Mining Operations

The company holds a 25 percent participating interest in Syncrude, a joint venture established to recover shallow deposits of oil sands using open-pit mining methods, to extract the crude bitumen, and to produce a high-quality, light (32 degree API), sweet, synthetic crude oil. The Syncrude operation, located near Fort McMurray, Alberta (see map), exploits a portion of the Athabasca Oil Sands Deposit. The location is readily accessible by public road. The produced synthetic crude oil is shipped from the Syncrude site to Edmonton, Alberta by Alberta Oil Sands Pipeline Ltd. Since startup in 1978, Syncrude has produced about 1.7 billion barrels of synthetic crude oil.

Syncrude has an operating license issued by the Province of Alberta which is effective until 2035. This license permits Syncrude to mine oil sands and produce synthetic crude oil from approved development areas on oil sands leases. Syncrude holds eight oil sands leases covering about 100,500 hectares (248,300 acres) in the Athabasca Oil Sands Deposit. Issued by the Province of Alberta, the leases are automatically renewable as long as oil sands operations are ongoing or the leases are part of an approved development plan. Syncrude leases 10, 12, 17, 22 and 34 (containing proven reserves) and leases 29, 30 and 31 (containing no proven reserves) are included within a development plan approved by the Province of Alberta. There were no known previous commercial operations on these leases prior to the start-up of operations in 1978.

As of January 1, 2002, the greater of 25 percent deemed net profit royalty or one percent gross royalty applies to all Syncrude production after the deduction of new capital expenditures.

The Government of Canada had issued an order that expired at the end of 2003 which provided for the remission of any federal income tax otherwise payable by the participants as the result of the non-deductibility from the income of the participants of amounts receivable by the Province of Alberta as a royalty or otherwise with respect to Syncrude. That remission order excluded royalty payable on production for the Aurora project.

Operations at Syncrude involve three main processes: open pit mining, extraction of crude bitumen and upgrading of crude bitumen into synthetic crude oil. The Base mine (lease 17) has now been mined out and only remnants are being removed using trucks and shovels. In the North mine (leases 17 and 22) and in the Aurora mine (leases 10, 12 and 34), truck, shovel and hydrotransport systems are used. The extraction facilities, which separate crude bitumen from sand, are capable of processing approximately 675,000 tonnes (740,000 tons) of oil sands a day, producing about 24 million cubic metres (150 million barrels) of crude bitumen a year. This represents recovery capability of about 93 percent of the crude bitumen contained in the mined oil sands.

Crude bitumen extracted from oil sand is refined to a marketable hydrocarbon product through a combination of carbon removal in three large, high temperature, fluid coking vessels and by hydrogen addition in high temperature, high pressure, hydrocracking vessels. These processes remove carbon and sulphur and reformulate the crude into a low viscosity, low sulphur, high quality synthetic crude oil product. In 2006, the upgrading process yielded 0.849 cubic metres of synthetic crude oil per cubic metre of crude bitumen (0.849 barrels of synthetic crude oil per barrel of crude bitumen). In 2006, about 44 percent of the synthetic crude oil was processed by Edmonton area refineries and the remaining 56 percent was pipelined to refineries in eastern Canada or exported to the United States. Electricity is provided to Syncrude by a 270 megawatt electricity generating plant and a 160 megawatt electricity generating plant, both located at Syncrude. The generating plants are owned by the Syncrude participants. Recycled water is the primary water source, and incremental raw water is drawn, under license, from the Athabasca River. The company s 25 percent share of net investment in plant, property and equipment, including surface mining facilities, transportation equipment and upgrading facilities is about $3.4 billion.

In 2006, Syncrude s net production of synthetic crude oil was about 37,100 cubic metres (233,600 barrels) per day and gross production was about 41,000 cubic metres (258,100 barrels) per day. The company s share of net production in 2006 was about 9,300 cubic metres (58,400 barrels) per day.

In 2000, Syncrude completed development of the first stage of the Aurora mine. The Aurora investment involved extending mining operations to a new location about 35 kilometres (22 miles) from the main Syncrude site and expanding upgrading capacity. In 2001, the Syncrude owners approved another major expansion of upgrading capacity and further development of the Aurora mine. The second Aurora mining and extraction development became fully operational in 2004. The increased upgrading capacity came on stream in 2006. These projects increased total production capacity to about 56,400 cubic metres (355,000 barrels) of synthetic crude oil a day. The company s share of total project costs was $2.1 billion. Additional mining trains in the North mine and Aurora mine were also completed in 2005. There are no approved plans for major future expansion projects.

On November 1, 2006, the company announced that it plans to enter into a management services agreement with Syncrude to provide operational, technical and business management services to Syncrude. The company has a final checkpoint in the second quarter of 2007 to confirm or cancel the agreement following completion of an opportunity assessment study.

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The following table sets forth certain operating statistics for the Syncrude operations:

	2006	2005	2004	2003	2002
Total mined overburden (1)					
millions of cubic metres	98.0	74.2	76.6	83.5	77.9
millions of cubic yards	128.2	97.1	100.3	109.2	102.0
Mined overburden to oil sands ratio (1)	1.18	1.02	0.94	1.15	1.05
Oil sands mined					
millions of tonnes	175.0	152.7	170.9	152.4	156.5
millions of tons	195.5	168.0	188.0	168.0	172.1
Average bitumen grade (weight percent)	11.4	11.1	11.1	11.0	11.2
Crude bitumen in mined oil sands					
millions of tonnes	19.9	16.9	19.0	16.8	17.5
millions of tons	22.2	18.6	20.9	18.5	19.2
Average extraction recovery (percent)	90.3	89.1	87.3	88.6	89.9
Crude bitumen production (2)					
millions of cubic metres	17.7	15.1	16.4	14.7	15.5
millions of barrels	111.6	94.2	103.3	92.3	97.8
Average upgrading yield (percent)	84.9	85.3	85.5	86.0	86.3
Gross synthetic crude oil produced					
millions of cubic metres	15.2	12.6	14.1	12.5	13.5
millions of barrels	95.5	79.3	88.4	78.4	84.8
Company s net share (3)					
millions of cubic metres	3.4	3.1	3.4	3.0	3.3
millions of barrels	21.3	19.3	21.6	19.1	20.7

(1) Includes pre-stripping of mine areas and reclamation volumes.

(2) Crude bitumen production is equal to crude bitumen in mined oil sands multiplied by the average extraction recovery and the appropriate conversion factor.

(3) Reflects the company s 25 percent

interest in production, less applicable royalties payable to the Province of Alberta.

Other Oil Sands Activity

The company holds a 100 percent interest in approximately 13,500 hectares (33,400 acres) of surface mineable oil sands associated with the Kearl project in the Athabasca region of northern Alberta. The company is assessing a potential phased development of its oil sands in the area as part of the Kearl oil sands mining project. The company would hold about a 70 percent interest and would act as operator in the potential joint project with ExxonMobil Canada. A 400 well delineation drilling program to better define the available resource within the project area began in 2003 and was completed in 2005. The company filed a regulatory application with the Alberta Energy and Utilities Board for the Kearl oil sands project in July 2005. Hearings were held in November 2006 and a regulatory decision is expected in early 2007.

The company is continuing to evaluate other undeveloped oil sands acreage.

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Land Holdings

At December 31, 2006 and 2005, the company held the following oil and gas rights, and heavy oil and oil sands leases:

	Hectares						Acres					
	Developed		Undeveloped		Total		Developed		Undeveloped		Total	
	2006	2005	2006	2005	2006	2005	2006	2005	2006	2005	2006	2005
	(thousands)											
Western Provinces Conventional												
Gross (1)	1,032	1,055	154	181	1,186	1,236	2,550	2,607	381	447	2,931	3,054
Net (2)	407	430	95	109	502	539	1,006	1,063	235	269	1,241	1,332
Heavy Oil												
Gross (1)	41	41	174	193	215	234	101	101	430	477	531	578
Net (2)	41	41	105	105	146	146	101	101	260	260	361	361
Oil Sands												
Gross (1)	47	47	119	72	166	119	116	116	294	178	410	294
Net (2)	12	11	54	31	66	42	30	27	133	77	163	104
Canada Lands (3): Conventional												
Gross (1)	31	31	322	322	353	353	77	77	795	795	872	872
Net (2)	3	3	98	98	101	101	7	7	242	242	249	249
Atlantic Offshore Conventional												
Gross (1)	17	17	2,600	2,600	2,617	2,617	42	42	6,425	6,425	6,467	6,467
Net (2)	2	2	616	616	618	618	5	5	1,522	1,522	1,527	1,527
Total (4) :												
Gross (1)	1,168	1,191	3,369	3,368	4,537	4,559	2,886	2,943	8,325	8,322	11,211	11,265
Net (2)	465	487	968	959	1,433	1,446	1,149	1,203	2,392	2,370	3,541	3,573

(1) Gross hectares or acres include the interests of others.

(2) Net hectares or acres exclude the interests of others.

(3) Canada Lands include the Arctic Islands,

Beaufort Sea/Mackenzie Delta, and Other Northwest Territories, Nunavut and the Yukon.

(4) Certain land holdings are subject to modification under agreements whereby others may earn interests in the company s holdings by performing certain exploratory work (farm-out) and whereby the company may earn interests in others holdings by performing certain exploratory work (farm-in).

Exploration and Development

The company has been involved in the exploration for and development of petroleum and natural gas in the Western Provinces, in the Canada Lands (which include the Arctic Islands, the Beaufort Sea/Mackenzie Delta, and Other Northwest Territories, Nunavut and the Yukon) and in the Atlantic Offshore.

The company s exploration strategy in the Western Provinces is to search for hydrocarbons on its existing land holdings and especially near established facilities. Higher risk areas are evaluated through shared ventures with other companies.

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The following table sets forth the conventional and heavy oil net exploratory and development wells that were drilled or participated in by the company during the five years ended December 31, 2006.

	2006	**2005**	**2004**	**2003**	**2002**
Western and Atlantic Provinces:					
Conventional					
Exploratory					
Oil					
Gas	1		2	3	1
Dry Holes			1	1	2
Development					
Oil		2	3	4	1
Gas	192	155	207	89	42
Dry Holes	1	1	1	3	3
Heavy Oil (Cold Lake and other)					
Development					
Oil	174	87	218	118	332
Total	368	245	432	218	381

The 174 heavy oil development wells in 2006 were drilled to add new productive capacity from undeveloped areas of existing phases at Cold Lake. In 2004, there was an increase in gas development wells related to an increase in drilling in shallow gas fields. Weather related delays in 2005 resulted in a reduction in the number of wells drilled in the ongoing shallow gas development program.

At December 31, 2006, the company was participating in the drilling of 221 gross (181 net) exploratory and development wells.

Western Provinces

In 2006, the company had a working interest in three gross (one net) exploratory wells and 520 gross (366 net) development wells. The majority of the exploratory wells were directed toward extending reserves around existing fields.

Beaufort Sea/Mackenzie Delta

Substantial quantities of gas have been found by the company and others in the Beaufort Sea/Mackenzie Delta.

In 1999, the company and three other companies entered into an agreement to study the feasibility of developing Mackenzie Delta gas, anchored by three large onshore natural gas fields. The company retains a 100 percent interest in one of these fields.

The commercial viability of these natural gas resources, and the pipeline required to transport this natural gas to markets, is dependent on a number of factors. These factors include natural gas markets, support from northern parties, regulatory approvals, environmental considerations, pipeline participation, fiscal framework, and the cost of constructing, operating and abandoning the field production and pipeline facilities. There are complex issues to be resolved and many interested parties to be consulted, before any development could proceed.

In October 2001, the four companies and the Aboriginal Pipeline Group (APG), which represents aboriginal peoples of the Northwest Territories, signed a memorandum of understanding to pursue economic and timely development of a Mackenzie Valley pipeline. In 2002, the four companies completed a preliminary study of the feasibility of developing existing discoveries of Mackenzie Delta gas and based on the results of the study announced, together with the APG, their intention to begin preparing the regulatory applications needed to develop the gas resources, including construction of a Mackenzie Valley pipeline. In 2003, the Preliminary Information Package for the Mackenzie Gas Project was submitted to the regulatory authorities, and funding and participation agreements among the four companies, the APG and TransCanada PipeLines Limited were reached for the proposed Mackenzie

Valley pipeline. In late 2004, the four companies and the APG signed agreements covering the development and operations of the Mackenzie Valley pipeline. In October 2004, the main regulatory applications and environmental impact statement for the project were filed with the National Energy Board and other boards, panels and agencies responsible for assessing and regulating energy developments in the Northwest Territories. In November 2005, the National Energy Board was notified of the project proponents readiness to proceed to public hearings on the project. The public hearings by the Joint Review Panel and the National Energy Board commenced in early 2006. The National Energy Board concluded their scheduled hearings in December, while the Joint Review Panel, conducting the environmental and socio-economic review, extended hearings into 2007, announcing that it would require several extra months of hearings, and additional time to compile its report. In November 2006, a federal court ruling, relating to traditional land use by a First Nation along the pipeline route in Northern Alberta, added further delay to the process.

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Other land holdings include majority interests in 20 and minority interests in six Significant Discovery Licences granted by the Government of Canada as the result of previous oil and gas discoveries, all of which are managed by the company and majority interests in two and minority interests in 16 other Significant Discovery Licences and one production licence, managed by others.

Arctic Islands

The company has an interest in 16 Significant Discovery Licences and one production licence granted by the Government of Canada in the Arctic Islands. These licences are managed by another company on behalf of all participants. The company has not participated in wells drilled in this area since 1984.

Atlantic Offshore

The company manages five Significant Discovery Licences granted by the Government of Canada in the Atlantic offshore. The company also has minority interests in 27 Significant Discovery Licences, and six production licences, managed by others.

The company retains a 20 percent interest in two exploration licences for about 45,000 gross hectares (110,000 gross acres) acquired in 1998 and 1999 in the Sable Island area. One exploratory well was completed on each licence, without commercial success.

Also, the company retains a 70 percent interest in one exploration licence for about 113,000 gross hectares (279,000 gross acres) farther offshore in deeper water. In 2003, one exploratory well was drilled on this licence, without commercial success. The company is not planning further exploration in these areas.

In early 2004, the company acquired a 25 percent interest in eight deep water exploration licences offshore Newfoundland in the Orphan Basin for about 2,125,000 gross hectares (5,251,000 gross acres). In February 2005, the company reduced its interest to 15 percent through an agreement with another company. The company s share of proposed exploration spending is about $100 million with a minimum commitment of about $25 million. In 2004 and 2005, the company participated in 3-D seismic surveys in this area. An exploration well was spud in August 2006 with anticipated completion in early 2007. Two more exploration wells are planned by the end of 2008.

The company retains 100 percent interest in a single exploration licence for about 192,000 gross hectares (474,000 gross acres) in the Laurentian basin area offshore Newfoundland and Labrador.

Petroleum Products

Supply

To supply the requirements of its own refineries and condensate requirements for blending with crude bitumen, the company supplements its own production with substantial purchases from others.

The company purchases domestic crude oil at freely negotiated prices from a number of sources. Domestic purchases of crude oil are generally made under renewable contracts with 30 to 60 day cancellation terms.

Crude oil from foreign sources is purchased by the company at competitive prices mainly through Exxon Mobil Corporation (which has beneficial access to major market sources of crude oil throughout the world).

Refining

The company owns and operates four refineries. Two of these, the Sarnia refinery and the Strathcona refinery, have lubricating oil production facilities. The Strathcona refinery processes Canadian crude oil, and the Dartmouth, Sarnia and Nanticoke refineries process a combination of Canadian and foreign crude oil. In addition to crude oil, the company purchases finished products to supplement its refinery production.

In 2006, capital expenditures of about $230 million were made at the company s refineries. About 40 percent of those expenditures were on new facilities required to meet Government of Canada regulations on motor fuels with the remaining expenditures being primarily on safety and efficiency improvements, and environmental improvement projects.

The approximate average daily volumes of refinery throughput during the five years ended December 31, 2006, and the daily rated capacities of the refineries at December 31, 2001 and 2006, were as follows:

		Average Daily Volumes of Refinery Throughput (1) Year Ended December 31				Daily Rated Capacities at December 31 (2)	
	2006	2005	2004	2003	2002	2006	2001
		(thousands of cubic metres)					
Strathcona, Alberta	25.5	27.6	27.1	27.6	26.0	29.8	29.0
Sarnia, Ontario	17.6	16.9	17.2	14.7	16.5	19.2	19.2
Dartmouth, Nova Scotia	12.3	12.5	12.7	13.0	12.5	13.1	13.1
Nanticoke, Ontario	14.9	17.2	17.3	16.3	16.2	17.8	17.8
Total	70.3	74.1	74.3	71.6	71.2	79.9	79.1

		Average Daily Volumes of Refinery Throughput (1) Year Ended December 31				Daily Rated Capacities at December 31 (2)	
	2006	2005	2004	2003	2002	2006	2001
		(thousands of barrels)					
Strathcona, Alberta	160	174	170	174	163	187	182
Sarnia, Ontario	111	106	108	92	104	121	121
Dartmouth, Nova Scotia	77	79	80	82	78	82	82
Nanticoke, Ontario	94	108	109	102	102	112	112
Total	442	466	467	450	447	502	497

(1) Refinery throughput is the volume of crude oil and feedstocks that is processed in the refinery atmospheric distillation units.

(2) Rated capacities are based on definite specifications as to types of crude oil and feedstocks that are processed in the refinery atmospheric

distillation units, the products to be obtained and the refinery process, adjusted to include an estimated allowance for normal maintenance shutdowns. Accordingly, actual capacities may be higher or lower than rated capacities due to changes in refinery operation and the type of crude oil available for processing.

Refinery throughput was 88 percent of capacity in 2006, 5 percentage points below the previous year, primarily due to scheduled maintenance and project work.

Distribution

The company maintains a nation-wide distribution system, including 30 primary terminals, to handle bulk and packaged petroleum products moving from refineries to market by pipeline, tanker, rail and road transport. The company owns and operates crude oil, natural gas liquids and products pipelines in Alberta, Manitoba and Ontario and has interests in the capital stock of two products and three crude oil pipeline companies.

At December 31, 2006, the company did not own or operate any marine vessels.

Marketing

The company markets more than 700 petroleum products throughout Canada under well known brand names, most notably Esso and Mobil, to all types of customers.

The company sells to the motoring public through Esso service stations. On average during the year, there were about 1,960 sites of which about 650 were company owned or leased, but none of which were company operated. The company continues to improve its Esso service station network, providing more customer services such as car washes and convenience stores, primarily at high volume sites in urban centres.

The Canadian farm, residential heating and small commercial markets are served through about 100 sales facilities. Heating oil is provided through authorized dealers as well as through three company operated Home Comfort facilities in urban markets. The company also sells petroleum products to large industrial and commercial accounts as well as to other refiners and marketers.

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The approximate daily volumes of net petroleum products (excluding purchases/sales contracts with the same counterparty) sold during the five years ended December 31, 2006, are set out in the following table:

	2006	**2005**	**2004**	**2003**	**2002**
			(thousands a day)		
Gasolines:					
Cubic metres	32.7	33.4	33.2	33.0	32.9
Barrels	206	210	209	208	207
Heating, Diesel and Jet Fuels:					
Cubic metres	26.4	26.9	27.3	26.2	25.0
Barrels	166	169	172	165	157
Heavy Fuel Oils:					
Cubic metres	5.1	6.0	5.9	5.4	4.9
Barrels	32	38	37	34	31
Lube Oils and Other Products					
Cubic metres	7.7	7.6	7.0	5.8	6.4
Barrels	49	48	44	36	41
Net petroleum product sales:					
Cubic metres	71.9	73.9	73.4	70.4	69.2
Barrels	453	465	462	443	436

The total domestic sales of petroleum products as a percentage of total sales of petroleum products during the five years ended December 31, 2006, were as follows:

	2006	**2005**	**2004**	**2003**	**2002**
	96.1%	95.3%	93.0%	93.3%	91.5%

The company continues to evaluate and adjust its Esso service station and distribution system to increase productivity and efficiency. During 2006, the company closed or debranded about 110 Esso service stations, about 40 of which were company owned, and added about 70 sites. The company s average annual throughput in 2006 per Esso service station was 3.6 million litres, the same as in 2005. Average throughput per company owned or leased Esso service station was 6.1 million litres in 2006, an increase of about 0.3 million litres from 2005.

Chemicals

The company s chemicals operations manufacture and market ethylene, benzene, aromatic and aliphatic solvents, plasticizer intermediates and polyethylene resin. Its major petrochemical and polyethylene manufacturing operations are located in Sarnia, Ontario, adjacent to the company s petroleum refinery. There is also a heptene and octene plant located in Dartmouth, Nova Scotia.

The company s average daily sales of petrochemicals during the five years ended December 31, 2006, were as follows:

	2006	**2005**	**2004**	**2003**	**2002**
			(thousands a day)		
Petrochemicals:					
Tonnes	3.0	3.0	3.3	3.3	3.5
Tons	3.3	3.3	3.6	3.6	3.9

Research

In 2006, the company s research expenditures in Canada, before deduction of investment tax credits, were $56 million, as compared with $50 million in 2005, and $40 million in 2004. Those funds were used mainly for developing improved heavy crude oil recovery methods and better lubricants.

A research facility to support the company s natural resources operations is located in Calgary, Alberta. Research in these laboratories is aimed at developing new technology for the production and processing of crude bitumen. About 40 people were involved in this type of research in 2006. The company also participated in heavy oil recovery and processing research for oil sands development through its interest in Syncrude, which maintains research facilities in Edmonton, Alberta and through research arrangements with others.

In company laboratories in Sarnia, Ontario, research is mainly conducted on the development and improvement of lubricants and fuels. About 120 people were employed in this type of research at the end of 2006. Also in Sarnia, there are about 15 people engaged in new product development for the company s and Exxon Mobil Corporation s polyethylene injection and rotational molding businesses.

The company has scientific research agreements with affiliates of Exxon Mobil Corporation which provide for technical and engineering work to be performed by all parties, the exchange of technical information and the assignment and licensing of patents and patent rights. These agreements provide mutual access to scientific and operating data related to nearly every phase of the petroleum and petrochemical operations of the parties.

Environmental Protection

The company is concerned with and active in protecting the environment in connection with its various operations. The company works in cooperation with government agencies and industry associations to deal with existing and to anticipate potential environmental protection issues. In the past five years, the company has made capital expenditures of about $1.2 billion on environmental protection and facilities. In 2006, the company s capital expenditures relating to environmental protection totalled approximately $155 million, and are expected to be about $160 million in 2007.

The increased environmental expenditures over the past four years primarily reflect spending on two major projects. One project completed in 2004, costing about $650 million, reduced sulphur in motor gasolines, meeting a requirement of the Government of Canada. The second project completed in 2006 was to meet a new Government of Canada regulation requiring ultra-low sulphur on-road diesel fuel. In 2006, there were capital expenditures of about $95 million on this second project, which cost about $500 million in total. Capital expenditures on safety related projects in 2006 were approximately $15 million.

Human Resources

At December 31, 2006, the company employed full-time approximately 4,900 persons compared with about 5,100 at the end of 2005 and 6,100 at the end of 2004. During 2005, the company transferred about 700 employees to an affiliated company that provides services to the company and others. About nine percent of the company s employees are members of unions. The company continues to maintain a broad range of benefits, including illness, disability and survivor benefits, a savings plan and pension plan.

Competition

The Canadian petroleum, natural gas and chemical industries are highly competitive. Competition includes the search for and development of new sources of supply, the construction and operation of crude oil, natural gas and refined products pipelines and facilities and the refining, distribution and marketing of petroleum products and chemicals. The petroleum industry also competes with other industries in supplying energy, fuel and other needs of consumers.

Government Regulation

Petroleum and Natural Gas Rights

Most of the company s petroleum and natural gas rights were acquired from governments, either federal or provincial. Reservations, permits or licences are acquired from the provinces for cash and entitle the holder to obtain leases upon completing specified work. Leases may also be acquired for cash. A lease entitles the holder to produce petroleum and/or natural gas from the leased lands. The holder of a licence relating to Canada Lands and the Atlantic Offshore is generally required to make cash payments or to undertake specified work or amounts of exploration expenditures in order to retain the holder s interest in the land and may become entitled to produce petroleum or natural gas from the licenced land.

Crude Oil

Production

The maximum allowable gross production of crude oil from wells in Canada is subject to limitation by various regulatory authorities on the basis of engineering and conservation principles.

Exports

Export contracts of more than one year for light crude oil and petroleum products and two years for heavy crude oil (including crude bitumen) require the prior approval of the National Energy Board (the NEB) and the Government of Canada.

Natural Gas

Production

The maximum allowable gross production of natural gas from wells in Canada is subject to limitations by various regulatory authorities. These limitations are to ensure oil recovery is not adversely impacted by accelerated gas production practices. These limitations do not impact gas reserves, only the timing of production of the reserves, and did not have a significant impact on 2006 gas production rates. As well, these limitations do not apply to gas fields where there are no associated oil reserves.

Exports

The Government of Canada has the authority to regulate the export price for natural gas and has a gas export pricing policy which accommodates export prices for natural gas negotiated between Canadian exporters and U.S. importers.

Exports of natural gas from Canada require approval by the NEB and the Government of Canada. The Government of Canada allows the export of natural gas by NEB order without volume limitation for terms not exceeding 24 months.

Royalties

The Government of Canada and the provinces in which the company produces crude oil and natural gas impose royalties on production from lands where they own the mineral rights. Some producing provinces also receive revenue by imposing taxes on production from lands where they do not own the mineral rights.

Different royalties are imposed by the Government of Canada and each of the producing provinces. Royalties imposed by the producing provinces on crude oil vary depending on well production volumes, selling prices, recovery methods and the date of initial production. Royalties imposed by the producing provinces on natural gas and natural gas liquids vary depending on well production volumes, selling prices and the date of initial production. For information with respect to royalty rates for Norman Wells, Cold Lake and Syncrude, see Natural Resources Petroleum and Natural Gas Production .

Investment Canada Act

The Investment Canada Act requires Government of Canada approval, in certain cases, of the acquisition of control of a Canadian business by an entity that is not controlled by Canadians. In certain circumstances, the acquisition of natural resource properties may be considered to be a transaction that constitutes an acquisition of control of a Canadian business requiring Government of Canada approval.

The Act requires notification of the establishment of new unrelated businesses in Canada by entities not controlled by Canadians, but does not require Government of Canada approval except when the new business is related to Canada s cultural heritage or national identity. By virtue of the majority stock ownership of the company by Exxon Mobil Corporation, the company is considered to be an entity which is not controlled by Canadians.

The Company Online

The company s website www.imperialoil.ca contains a variety of corporate and investor information which is available free of charge, including the company s annual report on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K and amendments to these reports. These reports are made available as soon as reasonably practicable after they are filed or furnished to the U.S. Securities and Exchange Commission.

Item 1A. Risk Factors.

Volatility of Oil and Natural Gas Prices

The company s results of operations and financial condition are dependent on the prices it receives for its oil and natural gas production. 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. Any material decline in oil or natural gas prices could have a material adverse effect on the company s operations, financial condition, proven reserves and the amount spent to develop oil and natural gas reserves.

A significant portion of the company s production is heavy oil. The market prices for heavy oil differ from the established market indices for light and medium grades of oil principally due to the higher transportation and refining costs associated with heavy oil and limited refining capacity capable of processing heavy oil. As a result, the price received for heavy oil is generally lower than the price for medium and light oil, and the production costs associated with heavy oil are often relatively higher than for lighter grades. Future differentials are uncertain and increases in the heavy oil differentials could have a material adverse effect on the company s business.

The company does not use derivative markets to hedge or sell forward any part of production from any business segment.

Competitive Factors

The oil and gas industry is highly competitive, particularly in the following areas: searching for and developing new sources of supply; constructing and operating crude oil, natural gas and refined products pipelines and facilities; and the refining, distribution and marketing of petroleum products and chemicals. The company s competitors include major integrated oil and gas companies and numerous other independent oil and gas companies. The petroleum industry also competes with other industries in supplying energy, fuel and related products to customers.

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Competitive forces may result in shortages of prospects to drill, services to carry out exploration, development or operating activities and infrastructure to produce and transport production. It may also result in an oversupply of crude oil, natural gas, petroleum products and chemicals. Each of these factors could have a negative impact on costs and prices and, therefore, the company s financial results.

Environmental Risks

All phases of the upstream, downstream and chemicals businesses are subject to environmental regulation pursuant to a variety of Canadian federal, provincial and municipal laws and regulations, as well as international conventions (collectively, environmental legislation).

Environmental legislation imposes, among other things, restrictions, liabilities and obligations in connection with the generation, handling, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances to the environment. As well, environmental regulations are imposed on the qualities and compositions of the products sold and imported. Environmental legislation also requires that wells, facility sites and other properties associated with the company s operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, certain types of operations, including exploration and development projects and significant changes to certain existing projects, may require the submission and approval of environmental impact assessments. Compliance with environmental legislation can require significant expenditures and failure to comply with environmental legislation may result in the imposition of fines and penalties and liability for clean up costs and damages. The company cannot assure that the costs of complying with environmental legislation in the future will not have a material adverse effect on its financial condition or results of operations. The company anticipates that changes in environmental legislation may require, among other things, reductions in emissions to the air from its operations and result in increased capital expenditures. Future changes in environmental legislation could occur and result in stricter standards and enforcement, larger fines and liability, and increased capital expenditures and operating costs, which could have a material adverse effect on the company s financial condition or results of operations.

Climate Change

The Government of Canada has published a Notice of Intent to regulate emissions of carbon dioxide, methane, nitrous oxide and other emissions commonly referred to as greenhouse gases from various industrial activities, including oil and natural gas exploration and production, petroleum refining, and some chemical manufacturing. The Province of Alberta may also issue regulations under Alberta s *Climate Change and Emissions Management Act* limiting greenhouse gas emissions. Other provinces may also issue regulations limiting greenhouse gas emissions. Mandatory emissions limits may result in increased operating costs and capital expenditures for oil and natural gas producers, refiners and chemical manufacturers, and also may reduce demand for the company s products, possibly adversely affecting the company s business, financial condition, results of operations and cash flows. However, while the government has outlined broad guidelines of a possible regulatory framework, it has not determined what specific measures it might impose on companies. Consequently attempts to assess the magnitude of any impact on the company can only be speculative.

Other Regulatory Risk

The company is subject to a wide range of legislation and regulation governing its operations over which it has no control. Changes may affect every aspect of the company s operations and financial performance.

Need to Replace Reserves

The company s future conventional oil, heavy oil and natural gas reserves and production, and therefore cash flows, are highly dependent upon the company s success in exploiting its current reserve base and acquiring or discovering additional reserves. Without additions to the company s reserves through exploration, acquisition or development activities, reserves and production will decline over time as reserves are depleted. The business of exploring for, developing or acquiring reserves is capital intensive. To the extent cash flows from operations are insufficient to fund capital expenditures and external sources of capital become limited or unavailable, the company s ability to make the necessary capital investments to maintain and expand oil and natural gas reserves will be impaired. In addition, the company may be unable to find and develop or acquire additional reserves to replace oil and natural gas production at acceptable costs.

Other Business Risks

Exploring for, producing and transporting petroleum substances involve many risks, which even a combination of experience, knowledge and careful evaluation may not be able to mitigate. These activities are subject to a number of hazards which may result in fires, explosions, spills, blow-outs or other unexpected or dangerous conditions causing personal injury, property damage, environmental damage and interruption of operations. The company s insurance may not provide adequate coverage in certain unforeseen circumstances.

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Uncertainty of Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond the company s control. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flow therefrom are based upon a number of factors and assumptions made as of the date on which the reserve estimates were determined, such as geological and engineering estimates which have inherent uncertainties, the assumed effects of regulation by governmental agencies and future commodity prices and operating costs, all of which may vary considerably from actual results. All such estimates are, to some degree, uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable oil and natural gas reserves, the classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. Actual production, revenues, taxes and development, abandonment and operating expenditures with respect to its reserves will likely vary from such estimates, and such variances could be material.

Estimates with respect to reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves, rather than upon actual production history. Estimates based on these methods generally are less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be material, in the estimated reserves.

Project Factors

The company s results depend on its ability to develop and operate major projects and facilities as planned. The company s results will, therefore, be affected by events or conditions that affect the advancement, operation, cost or results of such projects or facilities. These risks include the company s ability to obtain the necessary environmental and other regulatory approvals; changes in resources and operating costs including the availability and cost of materials, equipment and qualified personnel; the impact of general economic, business and market conditions; and the occurrence of unforeseen technical difficulties.

Market Risk Factors

See Item 7A for a discussion of the impact of market risks and other uncertainties.

Item 2. Properties.

Reference is made to Item 1 above, and for the reserves of the Syncrude mining operations and oil and gas producing activities, reference is made to Item 8 of this report.

Item 3. Legal Proceedings.

Not applicable.

Item 4. Submission of Matters to a Vote of Security Holders.

Not applicable.

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PART II

Item 5. Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

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 5 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.

Quarterly Financial and Stock Trading Data

	2006 three months ended				2005 three months ended			
	Mar. 31	June 30	Sept. 30	Dec. 31	Mar. 31	June 30	Sept. 30	Dec. 31
	(millions of dollars)				(millions of dollars)			
Financial data								
Total revenues and other income (a)	5,818	6,688	6,651	5,631	5,958	6,802	7,711	7,743
Total expenses (a)	4,928	5,604	5,421	4,735	5,370	5,989	6,753	6,184
Income before income taxes	890	1,084	1,230	896	588	813	958	1,559
Income taxes	(299)	(247)	(408)	(102)	(195)	(274)	(306)	(543)
Net income	591	837	822	794	393	539	652	1,016
Per-share information (b)	(dollars)				(dollars)			
Net earnings basic	0.60	0.85	0.84	0.83	0.38	0.52	0.64	1.00
Net earnings diluted	0.59	0.85	0.84	0.83	0.37	0.52	0.64	1.00
Dividends (declared quarterly)	0.08	0.08	0.08	0.08	0.07	0.08	0.08	0.08
Share prices (b)	(dollars)				(dollars)			
Toronto Stock Exchange								
High	42.28	43.33	45.20	44.80	31.44	34.99	45.79	45.39
Low	35.36	36.18	35.33	34.31	22.50	27.37	33.33	32.28
Close	41.91	40.78	37.47	42.93	30.67	34.01	44.67	38.47
American Stock Exchange	($U.S.)				($U.S.)			
High	36.67	39.64	40.38	38.93	25.73	28.38	39.14	38.93
Low	30.54	32.50	31.64	29.99	18.27	21.57	27.46	27.47
Close	35.85	36.50	33.55	36.83	25.38	27.75	38.35	33.20

(a) Amounts for purchases/sales with same counterparty are included in both total revenues and other income and total expenses in 2005 quarterly data. Effective January 1, 2006, these purchases/sales were recorded on a net basis. See note 1 (page F-7), Summary of Significant Accounting Policies.

(b) Adjusted to reflect the May 2006 three-for-one share split.

The company s shares are listed on the Toronto Stock Exchange and are admitted to unlisted trading on the American Stock Exchange in New York. The symbol on these exchanges for the company s common shares is IMO. Share prices were obtained from stock exchange records adjusted for the three-for-one share split.

As of February 15, 2007 there were 13,490 holders of record of common shares of the company.

During the period October 1, 2006 to December 31, 2006, the company issued 176,325 common shares for $15.50 per share (following the three-for-one share split) as a result of the exercise of stock options by the holders of the stock options, who are all employees or former employees of the company, in transactions outside the U.S.A. which were not registered under the Securities Act in reliance on Regulation S thereunder.

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Issuer purchases of equity securities (1)

Period	(a) Total number of shares (or units) purchased	(b) Average price paid per share (or unit)	(c) Total number of shares purchased as part of publicly announced plans or programs	(d) Maximum number (or approximate dollar value) of shares that may yet be purchased under the plans or programs
October 2006 (October 1 - October 31)	1,315,785	$ 36.14	1,315,785	34,336,470
November 2006 (November 1 - November 30)	5,554,679	$ 41.65	5,554,679	28,721,476
December 2006 (December 1 - December 31)	3,031,537	$ 43.99	3,031,537	25,632,528

(1) The purchases were pursuant to a 12 month normal course share purchase program that was renewed on June 23, 2006 under which the company may purchase up to 48,772,466 of its outstanding common shares less any shares purchased by the employee savings plan and the company pension fund. If not previously terminated, the program will terminate on June 22, 2007.

Item 6. Selected Financial Data.

	2006	2005	2004	2003	2002
			(millions of dollars)		
Total operating revenues (a)	$ 24,505	$ 27,797	$ 22,408	$ 19,094	$ 16,890
Net income	3,044	2,600	2,052	1,705	1,214

Total assets	16,141	15,582	14,027	12,337	12,003
Long term debt	359	863	367	859	1,466
Other long term obligations	1,683	1,728	1,525	1,314	1,822
			(dollars)		
Net income/share basic (b)	3.12	2.54	1.92	1.53	1.07
Net income/share diluted (b)	3.11	2.53	1.91	1.53	1.07
Cash dividends/share (b)	0.32	0.31	0.29	0.29	0.28

(a) Total operating revenues include $4,894 million for 2005, $3,584 million for 2004, $2,851 million for 2003 and $2,431 million for 2002 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. See note 1 (page F-7), Summary of significant Accounting Policies.

(b) Adjusted to reflect the three-for-one share split.

Reference is made to the table setting forth exchange rates for the Canadian dollar, expressed in U.S. dollars, on page 2 of this report.

Item 7. 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 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 risk-assessed, 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 outlook

Natural resources

Imperial produces crude oil and natural gas for sale into large North American markets. Economic and population growth are expected to remain the primary drivers of energy demand, globally and in North America. The company expects the global economy to grow at an average rate of slightly less than 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 slightly less than two 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 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 a rate of about one percent per year. Oil and gas are expected to continue to supply two-thirds of Canadian energy demand. It is expected that Canada will also be a growing supplier of energy to U.S. markets through this period.

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

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

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

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

Petroleum products

The downstream industry environment remains very competitive. While refining margins in 2006 were strong, long-term real refining margins globally have declined at a rate of about one percent per year over the past 20 years. Intense competition in the retail fuels market similarly has driven down real margins. 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). Crude oil and many products are widely traded with published international prices. Prices for those commodities are determined by the marketplace, often an international marketplace, and are affected by many factors, including global and regional supply/demand balances, inventory levels, refinery operations, import/export balances, transportation logistics, seasonality and weather. Canadian wholesale prices in particular are largely determined by wholesale prices in adjacent U.S. regions. These prices and factors are continually monitored and provide input to operating decisions about which raw materials to buy, facilities to operate and products to make. However, there are no reliable indicators of future market factors that accurately predict changes in margins from period to period.

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

Imperial s fuels marketing business includes retail operations across Canada serving customers through about 1,960 Esso-branded service stations, of which about 650 are company-owned or leased, and wholesale and industrial operations through a network of 30 primary distribution terminals, as well as a secondary distribution network.

Chemicals

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

Results of operations

Net income in 2006 was $3,044 million or $3.11 a share the best year on record surpassing the previous record of $2,600 million or $2.53 a share in 2005 (2004 $2,052 million or $1.91 a share). Higher realizations for Cold Lake heavy oil and conventional crude oil contributed about $640 million and stronger refining, marketing and petrochemical margins about $60 million more to earnings when compared with 2005. Also positive to earnings were higher benefits from resolution of tax matters and the impact of tax rate changes of about $340 million and lower share-based compensation expenses of about $105 million. Partially offsetting these positive factors were the impacts of a stronger Canadian dollar of about $275 million, lower natural gas realizations of about $150 million, lower gains on asset divestments of about $130 million, higher planned refinery maintenance and capital project effects of about $100 million and a heavier mix of resources volumes of about $60 million.

Natural resources

Net income from natural resources was a record $2,376 million, exceeding the previous record achieved in 2005 of $2,008 million (2004 $1,517 million). Cold Lake heavy oil and conventional crude oil realizations were stronger by about $640 million compared with 2005. These positive items were partially offset by lower natural gas realizations of about $150 million and the negative impact of a higher Canadian dollar of about $200 million. The impact of natural resources volumes was unfavourable by about $60 million due to mix effects with lower conventional crude oil volumes being partially offset by higher Syncrude volumes. Higher production at Cold Lake was essentially offset by higher royalties. Tax expense in 2006 was lower by about $290 million, primarily from reductions in federal and Alberta tax rates and higher benefits from resolution of tax matters. Gains from asset divestments were lower by about $130 million compared with 2005.

Financial statistics

	2006	2005	2004	2003	2002
			(millions of dollars)		
Net income	$ 2,376	$ 2,008	$ 1,517	$ 1,174	$ 1,052
Operating revenues	8,456	8,189	6,580	5,584	4,790

World crude oil prices, denominated in U.S. dollars, were higher in 2006 than in the previous year. The annual average price of Brent crude oil, the most actively traded North Sea crude and a common benchmark of world oil markets, was about $65 (U.S.) a barrel in 2006, a more than 19 percent increase over the average price of $55 in 2005 (2004 $38). However, the company s Canadian-dollar realizations for conventional crude oil increased to a lesser extent because of a stronger Canadian dollar. Average realizations for conventional crude oil during the year were $68.58 (Cdn) a barrel, an increase of six percent from $64.48 in 2005 (2004 $48.96).

Average realizations for Cold Lake heavy oil were higher by over 40 percent in 2006, reflecting both increases in light crude oil prices and a narrowing price spread between light crude oil and Cold Lake heavy oil more consistent with historical trend levels.

Prices for Canadian natural gas in 2006 were lower than the previous year. The average of 30-day spot prices for natural gas at the AECO hub in Alberta was about $7.41 a thousand cubic feet in 2006, compared with $9.01 in 2005 (2004 $6.80). The company s average realizations on natural gas sales were $7.24 a thousand cubic feet, compared with $9 in 2005 (2004 $6.78).

Average realizations and prices

	2006	2005	2004	2003	2002
			(Canadian dollars)		
Conventional crude oil realizations (a barrel)	$ 68.58	$ 64.48	$ 48.96	$ 40.10	$ 36.81
Natural gas liquids realizations (a barrel)	40.75	40.00	33.78	32.09	23.38

Natural gas realizations (a thousand cubic feet)	7.24	9.00	6.78	6.60	4.02
Par crude oil price at Edmonton (a barrel)	73.75	69.86	53.26	43.93	40.44
Heavy oil price at Hardisty (Bow River, a barrel)	51.90	45.62	37.98	33.00	31.85

Total gross production of crude oil and natural gas liquids (NGLs) averaged 272,000 barrels a day, compared with 261,000 barrels in 2005 (2004 262,000).

Gross heavy oil production at the company s wholly owned facilities at Cold Lake was a record 152,000 barrels a day, surpassing the previous record of 139,000 barrels in 2005 (2004 126,000), due to the cyclic nature of production at Cold Lake and increased volumes from the ongoing development drilling program.

Production from the Syncrude oil sands operation, in which the company has a 25 percent interest, was higher during 2006 as a result of lower maintenance activities and new production volume from the new coker unit at the Stage 3 expansion project. Gross production of upgraded crude oil increased to 258,000 barrels a day from

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214,000 barrels in 2005 (2004 238,000). Imperial s share of average gross production increased to 65,000 barrels a day from 53,000 barrels in 2005 (2004 60,000).

Gross production of conventional oil decreased to 31,000 barrels a day from 38,000 barrels in 2005 (2004 43,000) as a result of the impact of divested properties and the natural decline in Western Canadian reservoirs.

Gross production of NGLs available for sale averaged 24,000 barrels a day in 2006, down from 31,000 barrels in 2005 (2004 33,000), mainly due to the declining NGL content of Wizard Lake gas production.

Gross production of natural gas decreased to 556 million cubic feet a day from 580 million cubic feet in 2005 (2004 569 million). Lower production volumes were primarily due to the natural decline in the Western Canadian Basin.

In 2006, the company realized a gain of $76 million on divestment of assets. In 2005, the gain on divestment of assets was approximately $208 million.

Crude oil and NGLs production and sales (a)

	2006		2005		2004		2003		2002	
	gross	net	gross	net	gross	net	gross	net	gross	net
					(thousands of barrels a day)					
Cold Lake	152	127	139	124	126	112	129	116	112	106
Syncrude	65	58	53	53	60	59	53	52	57	57
Conventional crude oil	31	23	38	29	43	33	46	35	51	39
Total crude oil production	248	208	230	206	229	204	228	203	220	202
NGLs available for sale	24	19	31	25	33	26	28	22	27	21
Total crude oil and NGL production	272	227	261	231	262	230	256	225	247	223
Cold Lake sales, including diluent (b)	198		183		167		170		145	
NGL sales	29		39		42		39		40	

Natural gas production and sales (a)

	2006		2005		2004		2003		2002	
	gross	net	gross	net	gross	net	gross	net	gross	net
				(millions of cubic feet a day)						
Production (c)	556	496	580	514	569	518	513	457	530	463
Sales	513		536		520		460		499	

(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 the 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.

Operating costs decreased by one percent in 2006. Lower energy and other operating costs more than offset higher Syncrude expenses.

In November, the company announced plans to enter into a management services agreement with Syncrude Canada Ltd., the operating company for the Syncrude joint venture. The company has a final checkpoint in the second quarter of 2007 to confirm or cancel the agreement following completion of an opportunity assessment study.

Petroleum products

Net income from petroleum products was $624 million or 2.4 cents a litre in 2006, compared with $694 million or 2.6 cents a litre in 2005 (2004 $556 million or 2.1 cents a litre). Earnings were negatively impacted by higher planned refinery maintenance and ultra-low sulphur diesel project activities, which impacted both refinery utilization and expenses by a total of about $100 million versus the prior year. Lower product sales volumes during the year were primarily a result of lower refinery production and had limited impact on earnings, as the reduction was primarily in lower margin refining and marketing sales channels. Earnings were also negatively impacted by a stronger Canadian dollar of about $65 million. These factors were partially offset by the net positive effect of resolution of tax matters and the impact of the tax rate change, totalling about $55 million, and stronger refining and marketing margins.

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Financial statistics

	2006	2005	2004	2003	2002
			(millions of dollars)		
Net income	$ 624	$ 694	$ 556	$ 462	$ 147
Operating revenues (a)	20,783	24,017	19,169	16,004	14,400

Sales of petroleum products

	2006	2005	2004	2003	2002
			(millions of litres a day (b))		
Gasolines	32.7	33.4	33.2	33.0	32.9
Heating, diesel and jet fuels	26.4	26.9	27.3	26.2	25.0
Heavy fuel oils	5.1	6.0	5.9	5.4	4.9
Lube oils and other products	7.7	7.6	7.0	5.8	6.4
Net petroleum product sales	71.9	73.9	73.4	70.4	69.2
Total domestic sales of petroleum products (percent)	96.1	95.3	93.0	93.3	91.5

Refinery utilization

	2006	2005	2004	2003	2002
			(thousands of barrels a day (b))		
Total refinery throughput (c)	442	466	467	450	447
Refinery capacity at December 31	502	502	502	502	499
Utilization of total refinery capacity (percent)	88	93	93	90	90

(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. See note 1, summary of significant Accounting Policies, on page F-9.

(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.

One thousand litres is approximately 6.3 barrels.

Margins were stronger in the refining segment of the industry in 2006. However, the effects of stronger industry margins were reduced partially by a higher Canadian dollar. Marketing margins in 2006 were slightly higher than the low levels of 2005.

Impacted by higher planned maintenance and ultra-low sulphur diesel project activities, refinery utilization for 2006 at 88 percent was lower than the record performance level of 93 percent in both 2005 and 2004.

The company s total sales volumes, excluding those resulting from reciprocal supply agreements with other companies, were 71.9 million litres a day, compared with 73.9 million litres in 2005 (2004 73.4 million). Lower refinery production was the main reason for the decline.

Operating costs in 2006 were essentially the same as the previous year.

Chemicals

Net income from chemicals operations was $143 million in 2006, the best on record, compared with $121 million in 2005 (2004 $109 million). Improved industry margins for polyethylene and intermediate products were the main contributors to higher earnings.

Financial statistics

	2006	**2005**	**2004**	**2003**	**2002**
			(millions of dollars)		
Net income	$ 143	$ 121	$ 109	$ 44	54
Operating revenues	1,704	1,665	1,509	1,232	1,164

Sales

	2006	**2005**	**2004**	**2003**	**2002**
			(thousands of tonnes a day (a))		
Polymers and basic chemicals	2.2	2.1	2.4	2.4	2.5
Intermediate and others	0.8	0.9	0.9	0.9	1.0
Total chemicals	3.0	3.0	3.3	3.3	3.5

(a) Calculated by dividing total

volumes for the
year by the
number of days
in the year.

The average industry price of polyethylene was $1,703 a tonne in 2006, essentially unchanged from $1,708 a tonne in 2005 (2004 $1,584).

Sales of chemicals were 3,000 tonnes a day, unchanged from 2005 (2004 3,300 tonnes).

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Operating costs in the chemicals segment for 2006 were about four percent lower than 2005, reflecting lower direct operating expenses.

Corporate and other

Net income from corporate and other was negative $99 million in 2006, compared with negative $223 million in 2005 (2004 negative $130 million). Favourable earnings effects were due mainly to lower share-based compensation expenses.

Liquidity and capital resources

Sources and uses of cash

	2006	2005
	(millions of dollars)	
Cash provided by/(used in)		
Operating activities	$ 3,587	$ 3,451
Investing activities	(965)	(992)
Financing activities	(2,125)	(2,077)
Increase/(decrease) in cash and cash equivalents	497	382
Cash and cash equivalents at end of year	$ 2,158	$ 1,661

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

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

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

Cash flow from operating activities

Cash provided by operating activities was $3,587 million, versus $3,451 million in 2005 (2004 $3,312 million). Increases in cash flow in 2006 were driven primarily by higher net income and lower overall working capital balances.

Capital and exploration expenditures

Total capital and exploration expenditures were $1,209 million in 2006, compared with $1,475 million in 2005 (2004 $1,445 million).

The funds were used mainly to invest in Cold Lake and Syncrude to maintain and expand production capacity, improve operating efficiency, reduce the sulphur content of diesel fuel and upgrade the network of Esso retail outlets. About $170 million was spent on projects related to reducing the environmental impact of the company s operations and improving safety, including about $95 million on the $500-million project to produce ultra-low sulphur diesel.

The following table shows the company s capital and exploration expenditures for natural resources during the five years ending December 31, 2006:

	2006	2005	2004	2003	2002
			(millions of dollars)		
Exploration	$ 32	$ 43	$ 60	$ 57	$ 39
Production	237	232	234	181	143
Heavy oil and oil sands	518	662	819	769	804
Total capital and exploration expenditures	$ 787	$ 937	$ 1,113	$ 1,007	$ 986

For the natural resources segment, about 85 percent of the capital and exploration expenditures in 2006 was focused on growth opportunities. Significant expenditures during the year were made to ongoing development

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drilling at Cold Lake and to Syncrude for the company s share of the Stage 3 upgrader expansion project. Sustained operation of the upgrader expansion project began in August 2006, following a prolonged start-up period.

Other 2006 investment included drilling at conventional fields in Western Canada, advancing the Mackenzie gas and Kearl oil sands projects, and exploration off the East Coast of Canada.

The Mackenzie gas project is facing significant cost and schedule pressures brought on by unprecedented global demands for energy infrastructure. There are also uncertainties related to the regulatory and permitting process and the remaining benefits and access agreements. The company s current work efforts are focused on completing regulatory hearings, advancing approval of permits, finalizing remaining benefits and access agreements, establishing an appropriate fiscal framework with the federal government, advancing potential shipping agreements and continuing paced engineering, technical and cost-reduction efforts.

Regulatory hearings by the joint federal and provincial review panel on the Kearl oil sands project were completed in November 2006 and a decision is expected in early 2007. The company s current efforts are focused on design optimization to improve project economics and reduce project execution risk. Once this work is completed and a regulatory decision is received, project timing will be determined.

Drilling of a wildcat exploration well began with co-venturers in the Orphan Basin, a frontier basin located off the East Coast of Newfoundland. Two more exploration wells are planned by the end of 2008. Imperial holds a 15-percent interest in eight deepwater exploration licences in the basin.

Planned capital and exploration expenditures in natural resources are expected to be about $700 million in 2007, with over 75 percent of the total focused on growth opportunities. Investments are mainly planned for development drilling at Cold Lake and conventional oil and gas operations in Western Canada, facilities improvement at Syncrude, the Mackenzie gas project, the Kearl oil sands project and exploration off the East Coast.

The following table shows the company s capital expenditures in the petroleum products segment during the five years ending December 31, 2006:

	2006	2005	2004	2003	2002
			(millions of dollars)		
Marketing	$ 97	$ 91	$ 85	$ 91	$ 133
Refining and supply	248	368	178	369	399
Other (a)	16	19	20	18	57
Total capital expenditures	$ 361	$ 478	$ 283	$ 478	$ 589

(a) Consists primarily of real estate purchases.

For the petroleum products segment, capital expenditures were $361 million in 2006, compared with $478 million in 2005 (2004 $283 million). The company invested about $95 million in refining operations and other facilities during the year as part of a three-year, $500-million project to reduce sulphur content in diesel. The project was completed in 2006 and the company was able to fully meet all new government regulations on ultra-low sulphur diesel from all of its facilities across Canada by the required schedules. More than $150 million was invested in other refinery projects to improve energy efficiency and increase yield. Major investments were also made to upgrade the network of Esso service stations during the year.

Capital expenditures for the petroleum products segment in 2007 are expected to be about $250 million. Major items include additional investment in the refineries on improving energy efficiencies and increasing yield and continued enhancements to the company s retail network.

The following table shows the company s capital expenditures for its chemicals operations during the five years ending December 31, 2006:

	2006	2005	2004	2003	2002
			(millions of dollars)		
Capital expenditures	$ 13	$ 19	$ 15	$ 41	$ 25

Of the capital expenditures for chemicals in 2006, the major investment focused on improving energy efficiency and yields.

Planned capital expenditures for chemicals in 2007 will be about $15 million.

Total capital and exploration expenditures for the company in 2007, which will focus mainly on growth and productivity improvements, are expected to total about $1 billion and will be financed from internally generated funds.

Cash flow from financing activities

In June, the company renewed the normal course issuer bid (share-repurchase program) for another 12 months. During 2006, the company purchased about 45.5 million shares for $1,818 million (2005 52.5 million

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shares for $1,795 million). Since Imperial initiated its first share-repurchase program in 1995, the company has purchased close to 800 million shares representing about 46 percent of the total outstanding at the start of the program with resulting distributions to shareholders of about $10.5 billion.

The company declared dividends totalling 32 cents a share in 2006, up from 31 cents in 2005 (2004 29 cents). Regular annual per-share dividends paid have increased in each of the past 12 years and, since 1986, payments per share have grown by 80 percent.

Total debt outstanding at the end of 2006, excluding the company s share of equity company debt, was $1,437 million, compared with $1,439 million at the end of 2005 (2004 $1,443 million). Debt represented 17 percent of the company s capital structure at the end of 2006, compared with 18 percent at the end of 2005 (2004 19 percent).

Debt-related interest incurred in 2006, before capitalization of interest, was $63 million, up from $45 million in 2005 (2004 $37 million). The average effective interest rate on the company s debt was 4.2 percent in 2006, compared with 3.1 percent in 2005 (2004 2.8 percent).

Financial percentages and ratios

	2006	**2005**	**2004**	**2003**	**2002**
Total debt as a percentage of capital (a)	17	18	19	21	24
Interest coverage ratios					
Earnings basis (b)	66	88	83	64	46
Cash-flow basis (c)	77	101	108	80	63

(a) Current and long-term portions of debt (page F-5), divided by debt and shareholders equity (page F-5).

(b) Net income (page F-3), debt-related interest before capitalization (page F-19, note 14) and income taxes (page F-3) divided by debt-related interest before capitalization.

(c) Cash flow from net income adjusted for other non-cash items (page F-4), current income tax expense (page F-11, note 5) and debt-related interest before capitalization (page F-19, note 14) divided by debt-related interest before capitalization.

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.

Effective May 23, 2006, the issued common shares of the company were split on a three-for-one basis and the number of authorized shares was increased from 450 million to 1,100 million. The prior period number of shares outstanding and shares purchased, as well as net income and dividends per share, have been adjusted to reflect the three-for-one split.

Contractual obligations

The following table shows the company s contractual obligations outstanding at December 31, 2006. It provides data for easy reference from the consolidated balance sheet and from individual notes to the consolidated financial statements.

	Financial Statement Note Reference	Payment due by period			
		2007	2008 to 2011	2012 and beyond	Total Amount
		(millions of dollars)			
Long-term debt and capital leases(a)	Note 4	$ 907	$ 332	$ 27	$ 1,266
Operating leases(b)	Note 11	53	172	48	273
Unconditional purchase obligations(c)	Note 11	58	167	40	265
Firm capital commitments(d)	Note 11	149	29		178
Pension and other post-retirement obligations(e)	Note 6	226	173	669	1,068
Asset retirement obligations(f)	Note 7	52	282	88	422
Other long-term agreements(g)	Note 11	271	677	240	1,188

(a) Includes capitalized lease obligations. Long-term debt amounts exclude the company s share of equity company debt.

(b) Minimum commitments for operating leases, shown on an undiscounted basis, primarily cover office buildings, rail cars and service stations.

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

(d) Firm capital commitments related to capital projects, shown on an undiscounted basis. The largest commitment outstanding at year-end 2006 was $41 million associated with the company s share of capital projects at Syncrude.

(e) The amount by which the projected 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 2007 and estimated benefit payments for unfunded plans in all years.

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

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

The company was contingently liable at December 31, 2006, for a maximum of $87 million relating to guarantees for purchasing operating equipment and other assets from its rural marketing associates upon expiry of the associate agreement or the resignation of the associate. The company expects that the fair value of the operating equipment and other assets so purchased would cover the maximum potential amount of future payments under the guarantees.

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

Recently issued Statement of Financial Accounting Standards

Accounting for uncertainty in income taxes

In June 2006, the Financial Accounting Standards Board (FASB) issued Interpretation No. 48 (FIN 48), Accounting for Uncertainty in Income Taxes . FIN 48 is an interpretation of FASB Statement No. 109 Accounting for Income Taxes and must be adopted by the company no later than January 1, 2007. The interpretation prescribes a comprehensive model for recognizing, measuring, presenting and disclosing in the financial statements uncertain tax positions that the company has taken or expects to take in its tax returns. The new standard requires that a tax benefit be recognized in the books only if it is more likely than not that a tax position will be sustained. Otherwise, a liability will need to be recorded to reflect the difference between the as-filed tax basis and the book tax basis. The new standard does not allow a restatement of the comparative prior periods.

The company expects to recognize a transition gain of approximately $14 million in shareholders equity upon adoption of FIN 48 in the first quarter of 2007. This gain reflects the recognition of several refund claims and associated interest, partly offset by increased liability reserves**.**

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 F-7.

Hydrocarbon reserves

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

The estimation of proved reserves is controlled by the company through long-standing approval guidelines. Reserve changes are made with a well-established, disciplined process driven by senior-level geoscience and engineering professionals (assisted by a central reserves group with significant technical experience), culminating in reviews with and approval by senior management and the company s board of directors. Notably, the company does not use specific quantitative 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 commitment toward the development of the reserves prior to booking.

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 and significant changes in long-term oil and gas price levels.

Beginning in 2004, the year-end 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. Regulations preclude the company from showing in this document the reserves that are calculated in a manner which is consistent with the basis that the company uses to make its investment decisions. The use of year-end prices for reserves estimation introduces short-term price volatility into the process since annual adjustments are required based on prices occurring on a single day. The company believes that this approach is inconsistent with the long-term nature of the natural resources business where production from individual projects often spans multiple decades. The use of prices from a single date is not relevant to the investment decisions made by the company, and annual variations in reserves based on such year-end prices are not of consequence to how the business is actually managed.

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 determination of reserves. This category can also include changes associated with the performance of improved recovery projects and significant changes in either development strategy or production equipment/facility capacity.

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

Impact of reserves on depreciation

The calculation of unit-of-production depreciation is a critical accounting estimate that measures the depreciation of natural resources assets. It is the ratio of actual volumes produced to total proved developed reserves (those reserves recoverable through existing wells with existing equipment and operating methods) applied to the asset cost. The volumes produced and asset cost are known and, while proved developed reserves have a high probability of recoverability, they are based on estimates that are subject to some variability. 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 impairment evaluation triggers include a significant decrease in current and projected prices or reserve volumes, an accumulation of project costs significantly in excess of the amount originally expected and historical and current operating losses.

In general, the company does not view temporarily low oil and gas 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, industry prices over the long term will continue to be driven by market supply and demand. 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 the crude oil and natural gas markets, petroleum products and chemicals. These are the same price assumptions that are used for capital investment decisions. The corporate plan is a fundamental annual management process that is the basis for setting near-term risk assessed operating and capital objectives in addition to providing the longer-term economic assumptions used for investment evaluation purposes. Any impairment tests that the company performs also make use of annual volumes based on individual field production profiles, which are also updated as part of the annual plan process.

The standardized measure of discounted future cash flows on page 35 is based on the year-end 2006 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 8.25 percent used in 2006 compares to actual returns of 9.82 percent and 9.99 percent achieved over the last 10- and 20- year periods ending December 31, 2006. If different assumptions are used, the expense and obligations could increase or decrease as a result. The company s potential exposure to changes in assumptions is summarized in note 6 to the consolidated financial statements on page F-12. At Imperial, differences between actual returns on plan assets versus long-term expected returns are not recorded in pension expense in the year the differences occur, but rather are amortized in pension expense as permitted by GAAP, along with other actuarial gains and losses, over the expected remaining service life of employees. Pension expense represented less than one percent of total expenses in 2006.

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 2006, the obligations were discounted at six percent and the accretion expense was $22 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.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

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.

In October 2006, the Government of Canada indicated its intent to introduce regulations to control greenhouse-gas emissions from major industrial facilities, although details of what measures will be imposed on companies have not been determined. Consequently, attempts to assess the impact on Imperial can only be speculative. The company will continue to monitor the development of legal requirements in this area.

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

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

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

Earnings sensitivities (a)

		millions of dollars after tax
Six dollars (U.S.) a barrel change in crude oil prices	+(-)	$ 270
Ninety cents a thousand cubic feet change in natural gas prices	+(-)	27
One cent (U.S) a litre change in sales margins for total petroleum products	+(-)	175
One cent (U.S.) a pound change in sales margins for polyethylene	+(-)	7
One-quarter percent decrease (increase) in short-term interest rates	+(-)	2
Nine cents decrease (increase) in the value of the Canadian dollar versus the U.S. dollar	+(-)	400

(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 2006. Each sensitivity calculation shows the impact on net income that results from a change in one factor, after tax and royalties and holding all other factors constant. While these sensitivities are applicable under current conditions, they may not apply proportionately to larger fluctuations.

The sensitivity of net income to changes in the Canadian dollar versus the U.S. dollar decreased from year-end 2005 by about $8 million (after tax) a year for each one-cent change, primarily due to the decrease in industry refining margins.

The sensitivity to changes in natural gas prices decreased from 2005 year-end by about $3 million (after tax) for each 10-cent change, primarily due to the company s lower natural gas production.

Item 8. Financial Statements and Supplementary Data.

Reference is made to the Index to Financial Statements on page F-1 of this report.

Syncrude Mining Operations

Syncrude s crude bitumen is contained within the unconsolidated sands of the McMurray Formation. Ore bodies are buried beneath 15 to 45 metres (50 to 150 feet) of overburden, have bitumen grades ranging from 4 to 14 weight percent and ore thickness of 35 to 50 metres (115 to 160 feet). 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. The in-place volume, depth and grade are established through extensive and closely spaced core drilling. In active mining areas, the approximate well spacing is 125 metres (150 wells per section) and in future mining areas, the well spacing is approximately 350 metres (20 wells per section). Proven reserves include the operating Base and North mines and the Aurora mine. In accordance with the long range mine plan approved by the Syncrude owners, there are an estimated 1,675 million tonnes (1,845 million tons) of extractable oil sands in the Base and North mines, with an average bitumen grade of 10.6 weight percent. In addition, at the Aurora mine, there are an estimated 4,155 million tonnes (4,580 million tons) of extractable oil sands at an average bitumen grade of 11.2 weight percent. After deducting royalties payable to the Province of Alberta, the company estimates its 25 percent net share of proven reserves at year end 2006 was equivalent to 114 million cubic metres (718 million barrels) of synthetic crude oil. Imperial s reserve assessment uses a 6 percent and 7 percent bitumen grade cut-off for the North mine and Aurora mine respectively, a 90 percent overall extraction recovery, a 97 percent mining dilution factor and an 88 percent upgrading yield.

The following table sets forth the company s share of net proven reserves of Synctude after deducting royalties payable to the Province of Alberta:

	Synthetic Crude Oil		
	Base mine and North mine	**Aurora mine**	**Total**
	(millions of cubic metres)		
Beginning of year 2004	53	71	124
Revision of previous estimate	(16)	16	
Production	(2)	(2)	(4)
End of year 2004	35	85	120
Revision of previous estimate			
Production	(1)	(2)	(3)
End of year 2005	34	83	117
Revision of previous estimate			
Production	(2)	(1)	(3)
End of year 2006	32	82	114

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	Synthetic Crude Oil		
	Base mine and North mine	Aurora mine	Total
	(millions of barrels)		
Beginning of year 2004	331	450	781
Revision of previous estimate	(103)	100	(3)
Production	(11)	(10)	(21)
End of year 2004	217	540	757
Revision of previous estimate			
Production	(9)	(10)	(19)
End of year 2005	208	530	738
Revision of previous estimate		1	1
Production	(9)	(12)	(21)
End of year 2006	199	519	718

Oil and Gas Producing Activities

The following information is provided in accordance with the United States Statement of Financial Accounting Standards No. 69, Disclosures about Oil and Gas Producing Activities .

Results of operations

	2006	2005	2004
	(millions of dollars)		
Sales to customers (1)	$ 2,601	$ 2,739	$ 2,160
Intersegment sales(1) (2)	1,251	1,013	976
	$ 3,852	$ 3,752	$ 3,136
Production expenses	1,016	1,035	870
Exploration expenses	32	31	44
Depreciation and depletion	467	583	565
Income taxes	564	716	547
Results of operations	$ 1,773	$ 1,387	$ 1,110

Capital and exploration expenditures

	2006	2005	2004
	(millions of dollars)		
Property costs(3)			
Proved	$	$	$
Unproved		7	1
Exploration costs	32	37	43

Development costs	496	330	408
Total capital and exploration expenditures	$ 528	$ 374	$ 452

Property, plant and equipment

	2006	2005
	(millions of dollars)	
Property costs(3)		
Proved	$ 3,226	$ 3,231
Unproved	139	162
Producing assets	6,392	6,111
Support facilities	184	174
Incomplete construction	595	432
Total cost	$ 10,536	$ 10,110
Accumulated depreciation and depletion	7,326	6,934
Net property, plant and equipment	$ 3,210	$ 3,176

(1) 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 (page F-10) in external sales , intersegment sales and in purchases of crude oil and products .

(2) 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.

(3) 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.

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Oil and Gas Reserves

	Crude oil and natural gas liquids			Natural Gas
	Conventional	Heavy Oil (2)	Total	Total
	(millions of cubic metres)			(billions of cubic metres)
Proved developed and undeveloped reserves (1)				
Beginning of year 2004	20	121	141	29
Revisions and improved recovery	1	(78)	(77)	(2)
(Sale)/purchase of reserves in place				
Discoveries and extensions				
Production	(3)	(6)	(9)	(5)
End of year 2004	18	37	55	22
Revisions and improved recovery		56	56	4
(Sale)/purchase of reserves in place	(2)		(2)	
Discoveries and extensions		2	2	
Production	(3)	(7)	(10)	(5)
End of year 2005	13	88	101	21
Revisions and improved recovery		37	37	4
(Sale)/purchase of reserves in place				
Discoveries and extensions				
Production	(2)	(7)	(9)	(5)
End of year 2006	11	118	129	20

(1) Proved developed and undeveloped reserves reported on this table represent net reserves. 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 101.325 kilopascals absolute at 15 degrees Celsius.

(2) 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 are from the Cold Lake production operations.

	Crude oil and natural gas liquids			Natural Gas
	Conventional	**Heavy Oil**(2)	**Total**	**Total**
		(millions of barrels)		(billions of cubic feet)
Beginning of year 2004	126	763	889	1,023
Revisions and improved recovery	11	(490)	(479)	(32)
(Sale)/purchase of reserves in place				(13)
Discoveries and extensions				3
Production	(22)	(41)	(63)	(190)
End of year 2004	115	232	347	791
Revisions and improved recovery		350	350	137
(Sale)/purchase of reserves in place	(12)		(12)	(6)
Discoveries and extensions		14	14	13
Production	(20)	(45)	(65)	(188)

End of year 2005	83	551	634	747
Revisions and improved recovery	4	236	240	140
(Sale)/purchase of reserves in place	(1)		(1)	(6)
Discoveries and extensions				10
Production	(15)	(46)	(61)	(181)
End of year 2006	71	741	812	710

(1) Proved developed and undeveloped reserves reported on this table represent net reserves. 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.

(2) 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 are from the Cold Lake production operations.

The information on the previous page describes changes during the years and balances of proved oil and gas and reserves at year-end 2004, 2005 and 2006. 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. Beginning in 2004, the year-end 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. Regulations preclude the company from showing in this document the reserves that are calculated in a manner which is consistent with the basis that the company uses to make its investment decisions. The use of year-end prices for reserves estimation introduces short-term price volatility into the process since annual adjustments are required based on prices occurring on a single day. The company believes that this approach is inconsistent with the long-term nature of the natural resources business where production from individual projects often spans multiple decades. The use of prices from a single date is not relevant to the investment decisions made by the company and annual variations in reserves based on such year-end prices are not of consequence to how the business is actually managed.

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 changes associated with the performance of improved recovery projects and significant changes in either development strategy or production equipment/facility capacity.

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

Reserves data do not include 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.

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.

Net proved developed and undeveloped reserves of crude oil and natural gas as of December 31 (1)

	2006	**2005**	**2004**	**2003**	**2002**
			(millions)		
Crude Oil:					
Conventional					
Cubic metres	11	13	18	20	23
Barrels	71	83	115	126	146
Heavy Oil					
Cubic metres	118	88	37	121	127
Barrels	741	551	232	763	801
Total					
Cubic metres	129	101	55	141	150
Barrels	812	634	347	889	947
Natural Gas			(billions)		

Cubic metres	20	21	22	29	35
Cubic feet	710	747	791	1,023	1,224

(1) Net reserves are the company s share of reserves after deducting the shares of mineral owners or governments or both.

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Net proved developed reserves of crude oil and natural gas as of December 31(1)

	2006	2005	2004	2003	2002
			(millions)		
Crude Oil:					
Conventional					
Cubic metres	11	13	18	19	22
Barrels	71	81	111	121	139
Heavy Oil					
Cubic metres	80	58	37	63	49
Barrels	501	368	232	398	308
Total					
Cubic metres	91	71	55	82	71
Barrels	572	449	343	519	447
Natural Gas			(billions)		
Cubic metres	17	18	20	24	27
Cubic feet	608	643	704	859	959

(1) Net reserves are the company s share of reserves after deducting the shares of mineral owners or governments or both.

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

As required by the Financial Accounting Standards Board, the standardized measure of discounted future net cash flows is computed by applying year end prices, costs and legislated tax rates and a discount factor of 10 percent to net proved reserves. The standardized measure includes costs for future dismantlement, abandonment and 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.

	2006	2005	2004
		(millions of dollars)	
Future cash flows	$ 36,751	$ 21,911	$ 11,625
Future production costs	(16,290)	(11,376)	(3,123)
Future development costs	(2,633)	(2,039)	(1,492)
Future income taxes	(5,039)	(2,777)	(2,260)
Future net cash flows	12,789	5,719	4,750
Annual discount of 10 percent for estimated timing of cash flows	(6,374)	(1,405)	(1,433)
Discounted future net cash flows	$ 6,415	$ 4,314	$ 3,317

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

	2006	2005	2004
		(millions of dollars)	
Balance at beginning of year	$ 4,314	$ 3,317	$ 4,738
Changes resulting from:			
Sales and transfers of oil and gas produced, net of production costs	(2,839)	(2,650)	(2,240)
Net changes in prices, development costs and production costs	4,221	3,343	(3,692)
Extensions, discoveries, additions and improved recovery, less related costs	(4)	(513)	(43)
Development costs incurred during the year	411	272	345
Revisions of previous quantity estimates	87	660	1,838
Accretion of discount	568	417	663
Net change in income taxes	(343)	(532)	1,708
Net change	2,101	997	(1,421)
Balance at end of year	$ 6,415	$ 4,314	$ 3,317

Within the past 12 months, the company has not filed oil and gas reserve estimates with any authority or agency of the United States.

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Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

None.

Item 9A. Controls and Procedures.

As indicated in the certifications in Exhibit 31.1 and 31.2 of this report, the company s principal executive officer and principal financial officer have evaluated the company s disclosure controls and procedures as of December 31, 2006. Based on that evaluation, these officers have concluded that the company s disclosure controls and procedures are appropriate and effective for the purpose of ensuring that material information relating to the company, including its consolidated subsidiaries, is made known to them by others within those entities, particularly during the period in which this annual report is being prepared.

Reference is made to page F-2 of this report for management s report on internal control over financial reporting.

Reference is made to page F-2 of this report for the report of the independent registered public accounting firm on management s assessment on internal control over financial reporting.

There has not been any change in the company s internal control over financial reporting that occurred during the company s fourth fiscal quarter of 2006 that has materially affected, or is reasonably likely to materially affect, the company s internal control over financial reporting.

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PART III

Item 10. Directors and Executive Officers of the Registrant.

The company currently has eight directors. Each director is elected to hold office until the close of the next annual meeting.

Each of the eight directors listed below has been nominated for re-election at the annual meeting of shareholders to be held May 1, 2007. All of the nominees are now directors and have been since the dates indicated.

The following table provides information on the nominees for election as directors.

Name and current principal occupation or employment	Last major position or office with the company or Exxon Mobil Corporation	Director since	Holdings (3)(4)(5)	
R.L. (Randy) Broiles Senior vice-president, resources division, Imperial Oil Limited	Global planning manager, ExxonMobil Production Company	July 21, 2005	Common shares of Imperial Oil Limited	5,000
			Deferred share units of Imperial Oil Limited	0
			Restricted stock units of Imperial Oil Limited	0
			Shares of Exxon Mobil Corporation(6)	59,641
T.J. (Tim) Hearn Chairman, president and chief executive officer, Imperial Oil Limited	President, Imperial Oil Limited	January 1, 2002	Common shares of Imperial Oil Limited	92,597
			Deferred share units of Imperial Oil Limited	305
			Restricted stock units of Imperial Oil Limited	681,400
			Shares of Exxon Mobil Corporation	10,106
J.M. (Jack) Mintz Professor, Joseph L. Rotman School of Management, University of Toronto (1)(2)		April 21, 2005	Common shares of Imperial Oil Limited	1,000
			Deferred share units of Imperial Oil Limited	394
			Restricted stock units of Imperial Oil Limited	6,000
			Shares of Exxon Mobil Corporation	0

R. (Roger) Phillips Retired president and chief executive officer, IPSCO Inc. (steel manufacturing)(1)(2)	April 23, 2002	Common shares of Imperial Oil Limited	9,000
		Deferred share units of Imperial Oil Limited	13,503
		Restricted stock units of Imperial Oil Limited	11,625
		Shares of Exxon Mobil Corporation	2,000

(Table continued on following page)

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Name and current principal occupation or employment	Last major position or office with the company or Exxon Mobil Corporation	Director since	Holdings(3)(4)(5)	
J.F. (Jim) Shepard Retired chairman and chief executive officer, Finning International Inc. (sale, lease, repair and financing of heavy equipment)(1)(2)		October 21, 1997	Common shares of Imperial Oil Limited	9,000
			Deferred share units of Imperial Oil Limited	21,428
			Restricted stock units of Imperial Oil Limited	11,625
			Shares of Exxon Mobil Corporation	0
P.A. (Paul) Smith Controller and senior vice-president, finance and administration, Imperial Oil Limited(2)	Corporate finance manager, Exxon Mobil Corporation	February 1, 2002	Common shares of Imperial Oil Limited	13,371
			Deferred share units of Imperial Oil Limited	0
			Restricted stock units of Imperial Oil Limited	192,000
			Shares of Exxon Mobil Corporation	1,190
S.D. (Sheelagh) Whittaker Retired managing director, Electronic Data Systems Limited (business and information technology services)(1)(2)		April 19, 1996	Common shares of Imperial Oil Limited	9,000
			Deferred share units of Imperial Oil Limited	28,957
			Restricted stock units of Imperial Oil Limited	11,625

		Shares of Exxon Mobil Corporation	0
V.L. (Victor) Young Corporate director of several corporations (1)(2)	April 23, 2002	Common shares of Imperial Oil Limited	10,250
		Deferred share units of Imperial Oil Limited	4,961
		Restricted stock units of Imperial Oil Limited	11,625
		Shares of Exxon Mobil Corporation	0

(1) Member of audit committee; member of environment, health and safety committee; member of executive resources committee; and member of nominations and corporate governance committee.

(2) Member of Imperial Oil Foundation board of directors

(3) The information includes the beneficial ownership of common shares of Imperial Oil Limited and shares of Exxon Mobil Corporation,

which information not being within the knowledge of the company, has been provided by the nominees individually.

(4) The company s plans for deferred share units and restricted stock units for selected employees and nonemployee directors are described on page 45 and pages 46 and 47, respectively.

(5) The numbers for restricted stock units and deferred share units represent the total of the restricted stock units and deferred share units received in 2006 after the three-for-one share split in May 2006, plus three times the number of restricted stock units and deferred share units granted before the share split and still held by the director.

(6) R.L. Broiles holds 16,641 common shares and 43,000

restricted shares
of Exxon Mobil
Corporation.

The ages of the directors, nominees for election as directors, and the five senior executives of the company are: Randy L. Broiles 49, Timothy J. Hearn 62, Jack M. Mintz 55, Roger Phillips 67, James F. Shepard 68, Paul A. Smith 53, Sheelagh D. Whittaker 59, Victor L. Young 61, Rob F. Lipsett 60, and John F. Kyle 64.

Certain of the directors hold positions as directors of other Canadian and U.S. reporting issuers as follows: Timothy J. Hearn   Royal Bank of Canada; Jack M. Mintz   Brookfield Asset Management Inc. and CHC Helicopter Corporation; Roger Phillips   Canadian Pacific Railway Company, Canadian Pacific Railway Limited, Cleveland-

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Cliffs Inc. and The Toronto-Dominion Bank; Sheelagh D. Whittaker CanWest Media Works Income Fund; and Victor L. Young Bell Aliant Regional Communications Income Fund, BCE Inc. and Royal Bank of Canada.

All of the directors and nominees for election as directors, except for Jack M. Mintz and Sheelagh D. Whittaker have been engaged for more than five years in their present principal occupations or in other executive capacities with the same firm or affiliated firms. During the five preceding years, Jack M. Mintz was president and chief executive officer of The C.D. Howe Institute until he retired in July 2006 and Sheelagh D. Whittaker was managing director of Electronic Data Systems until she retired in November 2005.

The following table provides information on the senior executives of the company.

Name and Office	**Office held since**
Timothy J. Hearn chairman of the board, president and chief executive officer	April 23, 2002
Paul A. Smith controller and senior vice-president, finance and administration	February 1, 2002
Randy L. Broiles senior vice-president, resources division	July 1, 2005
Rob F. Lipsett vice-president, human resources	October 1, 1999
John F. Kyle vice-president and treasurer	June 1, 1991

All of the above senior executives have been engaged for more than five years at their current occupations or in other executive capacities with the company or its affiliates. All senior executives hold office until their appointment is rescinded by the directors, or by the chief executive officer.

Audit committee

The company has an audit committee of the board of directors. The following directors are the members of the audit committee: R. Phillips, J.F. Shepard, S.D. Whittaker, V.L. Young, and J.M. Mintz.

Audit committee financial expert

The company s board of directors has determined that R. Phillips, S.D. Whittaker and V.L. Young meet the definition of audit committee financial expert and that they, J.F. Shepard and J.M. Mintz are independent, as that term is defined in Multilateral Instrument 52-110, the Securities and Exchange Commission rules and the listing standards of the American Stock Exchange and the New York Stock Exchange. The Securities and Exchange Commission has indicated that the designation of an audit committee financial expert does not make that person an expert for any purpose, or impose any duties, obligations or liability on that person that are greater than those imposed on members of the audit committee and board of directors in the absence of such designation or identification.

Code of ethics

The company has a code of ethics that applies to all employees, including its principal executive officer, principal financial officer and principal accounting officer. The code of ethics consists of the company s ethics policy, conflicts of interest policy, corporate assets policy, directorships policy, and procedures and open door communication. Those documents are available at the company s web site www.imperialoil.ca.

Item 11. Executive Compensation.

Composition of the company s compensation committee

The executive resources committee of the board of directors, composed of the independent directors, is responsible for corporate policy on compensation and for specific decisions on the compensation of the chief executive officer and key senior executives and officers reporting directly to that position. In addition to compensation matters, the committee is also responsible for succession plans and appointments to senior

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executive and officer positions, including the chief executive officer. During 2006, the membership of the executive resources committee was as follows:

R. Phillips Chair
V.L. Young Vice-chair
J.F. Shepard
S.D. Whittaker
J.M. Mintz

T.J. Hearn periodically attends meetings at the request of the committee.

Executive Resources Committee Report on Executive Compensation

Compensation Discussion and Analysis

The company s executive compensation program is designed to reinforce the company s orientation toward career employment and individual performance. It acknowledges the long-term nature of the company s business and its philosophy that the experience, skill and motivation of the company s executives are significant determinants of future business success. The compensation program emphasizes competitive salaries and performance-based incentives as the primary instruments to develop and retain key personnel.

The assessment of individual performance is conducted through the company s employee appraisal program. The appraisal program is a disciplined annual program that assesses business performance measures relevant to each employee, including the means by which performance is achieved, and involves comparative ranking of employee performance using a standard process throughout the organization and at all levels. The appraisal program is integrated with the compensation program and also with the executive development process which has been in place for more than 50 years and is the basis for planning individual development and succession planning for management positions.

In establishing compensation for the company s senior executives, the executive resources committee relies on market comparisons to a group of 25 major Canadian companies with revenues in excess of $1 billion a year. These market comparisons are prepared by independent external compensation consultants. On a case-by-case basis, depending on the scope of market coverage represented by a particular comparison, compensation is targeted to a range between the mid-point and the upper quartile of comparable employers, reflecting the company s emphasis on quality management.

The company s executive compensation program is composed of base salaries, cash bonuses and medium/long-term incentive compensation.

Base Salary

The company s salary ranges for executives were increased by 1.5 percent in 2005, 2.5 percent in 2006 and eight percent in 2007. The larger increase in 2007 was required to maintain the company s competitive position on salaries in the marketplace. Individual salary increases vary depending on each executive s performance assessment and other factors such as time in position and potential for advancement.

Cash Bonus

Cash bonuses are typically granted to about 80 executives to reward their contributions to the business during the past year. Bonuses are drawn from an aggregate bonus pool established annually by the executive resources committee based on the company s financial and operating performance.

In 2006, the overall bonus pool was increased by 7.5 percent over the previous year to reflect improved financial results and operating performance. In relation to this, the company s net income for 2006 was a record $3.044 billion (up 17 percent), return on shareholders equity was 44 percent, return on capital employed was 36 percent and total annual shareholders return was 13 percent. Changes in individual cash bonus awards vary depending on each executive s performance assessment.

Medium/Long-Term Incentive Compensation

A medium-term incentive compensation plan, called the earnings bonus unit plan, was introduced in 2001 and continues in use today. This plan is made available to selected executives to promote individual contribution to sustained improvement in the company s business performance and shareholder value. Earnings bonus units are generally equal to and granted in tandem with cash bonuses to approximately 80 executives annually. In 2006, each earnings bonus unit entitles the recipient to receive an amount equal to the company s cumulative net earnings per common share as announced each quarter beginning after the grant. Payout occurs after the fifth anniversary of the grant, or when the maximum settlement value per unit is reached, if earlier. If after five years the maximum payout has not been reached, payout will be prorated. In 2006, similar to the cash bonus pool, the earnings bonus units pool was increased by 7.5 percent over the previous year.

In December 2002, the company introduced a restricted stock unit plan, which is the company s long-term incentive compensation plan. The purpose of the plan is to align the interests of selected employees and non employee directors directly with the interests of shareholders. The restricted stock unit plan is a straightforward, primarily cash-based approach to long-term incentive compensation.

Grant level guidelines for the restricted stock unit program are generally held constant for long periods of time. In 2006, the guidelines were reviewed in light of the company s three-for-one share split. Given the significant appreciation in the company s share price over the past several years, restricted stock unit guidelines were adjusted on a two-for-one basis rather than the three-for-one share split. This had the effect of reducing grant values compared to earlier years.

Each unit granted in 2006 entitles the recipient to receive from the company, upon exercise, an amount equal to the five day average of the closing price of the company s shares preceding the exercise dates. Fifty percent of the units will be exercised by the company on the third anniversary of the grant date, and the remainder will be exercised on the seventh anniversary of the grant date. Recipients may receive the proceeds of the seventh year exercise as either one common share per unit or elect a cash payment. The company also pays the recipients cash with respect to each unexercised unit granted to the recipient corresponding in time and amount to the cash dividend that is paid by the company on a common share of the company.

In 2006, 964 employees were granted restricted stock units, including 92 executives.

CEO compensation

T.J. Hearn s salary is currently assessed to be within the range of the competitive target for the company s chairman, president and chief executive officer, namely, between the median and upper quartile of the competitive market. The target is consistent with the executive resources committee s view that the chairman, president and chief executive officer s salary should be above the average of salaries for chief executive officers of major Canadian companies, reflecting the company s executive development philosophy and the significance placed on experience and judgment in leading a large, complex operation.

In the case of T.J. Hearn, the committee s approach to cash bonuses is based on the company s financial and operating performance and on the committee s assessment of T.J. Hearn s effectiveness in leading the organization. The continuing progress being made in focusing the organization on advancing key strategic interests, safety, environmental performance, productivity, cost effectiveness and asset management were primary considerations in determining a cash bonus for the chairman, president and chief executive officer. T.J. Hearn s cash bonus was increased by 11 percent in 2006 to reflect his effectiveness in the position, the company s record financial performance and comparisons to other leading Canadian employers.

With respect to the company s medium term incentive program, the committee similarly awarded Mr. Hearn an 11 percent increase in his earnings bonus unit award compared to 2005 for the same reasons noted above for Mr. Hearn s cash bonus award.

For 2006, the committee adjusted the restricted stock unit grant for T.J. Hearn on an approximately two-for-one basis, as compared to the share split of three-for-one. This was consistent with the treatment for all other high performing executives and had the effect of reducing the award value on the grant date for T.J. Hearn.

Directors compensation

Directors fees are paid only to non-employee directors. For 2006, non-employee directors were paid an annual retainer of $35,000 and 3,000 restricted stock units for their services as directors, plus an annual retainer of $4,500 for each committee on which they served, an additional $5,000 for serving as chair of a committee and $2,000 for each board and board committee meeting attended. The restricted stock units issued to non-employee directors have the same features as the restricted stock units for selected key employees described on pages 46 and 47.

Starting in 1999, the non-employee directors have been able to receive all or part of their directors fees in the form of deferred share units for non-employee directors. The purpose of the deferred share unit plan for non-employee directors is to provide them with additional motivation to promote sustained improvement in the company s business performance and shareholder value by allowing them to have all or part of their directors fees tied to the future growth in value of the company s common shares. This plan is described on page 45.

While serving as directors in 2006, the aggregate cash remuneration paid to non-employee directors, as a group, was $418,125, and they received an additional 4,953 deferred share units, based on an aggregate of $234,375 of cash remuneration elected to be received as deferred share units. The non-employee directors, as a group, received an additional 444 deferred share units granted as the equivalent to the cash dividend paid on company shares during 2006 for previously granted deferred share units. In addition, the non-employee directors received 15,000 restricted stock units.

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Senior executive compensation

Summary Compensation Table

The following table shows the compensation for the chairman, president and chief executive officer and the four other senior executives of the company who were serving as senior executives at the end of 2006. This information includes the dollar value of base salaries, cash bonus awards, and units of other long term incentive compensation and certain other compensation.

		Annual Compensation			Long-Term Compensation					
					Awards			Payouts		
e and cipal tion	Year	Salary ($)	Bonus (2) ($)	Other Annual Compensation (3) ($)	Securities under options/SARs Granted (4) (#)	Shares or Units Subject to Resale Restrictions (5)(6) (#)	Shares or Units Subject to Resale Restrictions (5)(6) ($)	LTIP Payouts (7) ($)	All Other Compensation (8) ($)	Tot Compe (9 ($
rn an, nt and ecutive	2006	1,140,000	1,000,050	562,665		130,000 restricted stock units	5,623,800	900,000	34,200	9,2
						2 deferred share units	86			
	2005	1,100,000	900,000	385,028		193,200 restricted stock units	7,432,404	870,000	33,000	10
						3 deferred share units	94			
	2004	1,000,000	872,266	246,249		193,200 restricted stock units	4,582,060	750,000	30,000	7,4
						300 deferred share units	7,034			
ith ler and ice-	2006	404,167	197,267	111,279		35,100 restricted	1,518,426	193,050	24,250	2,4

					stock units				
nt, and tration	2005	398,333	193,675	87,198	55,200 restricted stock units	2,123,544	193,125	23,900	3,(
	2004	378,333	193,600	67,022	57,900 restricted stock units	1,373,195	183,000	22,700	2,:
biles (1) rice- nt, es (from 005)	2006	U.S. 325,083	U.S. 159,200	U.S. 421,481	11,000 restricted stock units	U.S. 815,760	U.S. 140,513	U.S. 21,705	U.S. 1,8
	2005	U.S. 159,000	U.S. 140,500	U.S. 112,214	11,000 restricted stock units	U.S. 641,740	U.S. 116,253	U.S. 10,175	U.S. 1,
osett esident, es	2006	364,583	191,406	140,106	28,800 restricted stock units	1,245,888	178,650	10,938	2,
	2005	360,000	178,850	107,810	42,300 restricted stock units	1,627,281	178,500	10,800	2,4
	2004	340,000	179,000	78,581	47,100 restricted stock units	1,117,055	166,700	10,200	1,8
e esident asurer	2006	365,000	119,145	124,081	20,800 restricted stock units	899,808	112,500	21,900	1,(
	2005	364,166	112,500	90,821	33,900 restricted stock units	1,304,133	171,375	21,850	2,(
	2004	359,583	172,105	74,585	39,600 restricted stock units	939,180	171,000	21,575	1,7

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(1) R.L. Broiles has been on a loan assignment from Exxon Mobil Corporation since July 1, 2005. His compensation was paid to him directly by Exxon Mobil Corporation in United States dollars, and is disclosed in United States dollars. Also, he received employee benefits under Exxon Mobil Corporation s employee benefit plans, and not under the company s employee benefit plans. The company reimburses Exxon Mobil Corporation for the compensation paid and employee benefits provided to him.

(2) Any part of bonus elected to be received as deferred share units is excluded.

(3) Amounts under Other Annual

Compensation , except for R.L. Broiles, consist of dividend equivalent payments on restricted stock units, interest paid in respect of deferred payments of bonuses and earnings bonus units and any costs associated with the personal use of the company aircraft. There is no tax assistance from the company for taxes related to personal use of the company aircraft. In 2006, the dividend equivalent payments were $195,792 for T.J. Hearn, $55,308 for P.A. Smith, $44,628 for R.F. Lipsett and $38,112 for J.F. Kyle. In 2006, the interest paid in respect of deferred payments of bonuses and earnings bonus units was $228,293 for T.J. Hearn, $10,971 for P.A. Smith, $58,746 for R.F. Lipsett and $37,185 for

J.F. Kyle. Also included is an earned benefits allowance. The earned benefits allowance in 2006 was $90,000 for T.J. Hearn, $45,000 for P.A. Smith, $35,000 for R.F. Lipsett and $35,000 for J.F. Kyle. For R.L. Broiles, the U.S. dollar amounts are the net payments by Exxon Mobil Corporation on account of Canadian income taxes and other compensation for assignment outside of the United States. Each year while on assignment, R.L. Broiles paid to Exxon Mobil Corporation amounts that were approximate to the income taxes that would have been imposed if he was resident in his originating country of employment. For R.L. Broiles, the amount includes dividend equivalent payments on restricted stock from Exxon Mobil Corporation.

(4) The company has not granted stock options since 2002. The stock option plan is described on page 46.

(5) These values include the number of units granted under the company s restricted stock unit plan and deferred share unit plan for selected executives described on pages 46 and 47 and page 45, respectively. The number of restricted stock units and deferred share units for 2006 are the number of units actually received. The numbers shown for restricted stock units and deferred share units for 2004 and 2005 represent three times the number of restricted stock units and deferred share units received in those years

before the three-for-one share split in May 2006. The values of the restricted stock units shown are the number of units multiplied by the closing price of the company s shares on the date of grant. The closing price on the date of grant of the restricted stock units was $23.72 in 2004, $38.47 in 2005 and $43.26 for 2006 (all on a post-split basis). The values of the deferred share units shown are the number of units multiplied by the closing price of the company s shares for the five consecutive days before the grant of the deferred share unit. T.J. Hearn is the only senior executive who holds deferred share units. R.L. Broiles participates in Exxon Mobil Corporation s restricted stock plan, which is similar to the company s restricted stock unit plan. Under that plan, R.L. Broiles was granted 11,000 restricted shares in 2006, whose value on the date of grant (November 28, 2006) was $815,760 U.S., based on a closing price of Exxon Mobil Corporation shares on the date of grant of $74.16 U.S.

(6) The table below shows the number and value of restricted stock units and deferred share units held as of December 31, 2006. The numbers for restricted stock units and deferred share units represent the total of the restricted stock units and deferred share units received in 2006 after the three-for-one share split in May 2006, plus three times the number of restricted stock units and deferred share units received before the share

split and still held by the employee. The closing price on December 31, 2006 was $42.93. R.L. Broiles participates in Exxon Mobil Corporation s restricted stock plan, which is similar to the company s restricted stock unit plan. Under that plan, R.L. Broiles holds 43,000 restricted shares whose value on December 31, 2006 was $3,295,090 U.S. based on a closing price for Exxon Mobil Corporation shares on December 31, 2006 of $76.63 U.S.

	Restricted Stock Units		Deferred Share Units	
Name	Total (#)	Total ($)	Total (#)	Total ($)
T.J. Hearn	681,400	29,252,502	305	13,094
P.A. Smith	192,000	8,242,560	0	0
R.L. Broiles				
R.F. Lipsett	154,650	6,639,125	0	0
J.F. Kyle	127,300	5,464,989	0	0

(7) Payouts were from 2005 earnings bonus unit that reached maximum value of $4.50 per unit in 2006. That

plan is described on page 46. R.L. Broiles participates in Exxon Mobil Corporation s earnings bonus unit plan, which is similar to the company s earnings bonus unit plan.

(8) Amounts under All Other Compensation , except for R.L. Broiles, are the company s contributions to the savings plan, which is a plan available to all employees. Under one of the options of that plan to which the senior executives subscribe, except for R.L. Broiles, the company matched employee contributions up to six percent of base salary per year; however, an employee may elect to receive an enhanced pension under the company s pension plan by foregoing three percent of the company s matching

contributions. The plan is intended to be primarily for retirement savings, although employees may withdraw their contributions prior to retirement. For R.L. Broiles, the amount is Exxon Mobil Corporation s contributions to its employee savings plan.

(9) Total Compensation for each of 2004, 2005 and 2006 consists of the total dollar value of Salary, Bonus, Other Annual Compensation, Shares or Units Subject to Resale Restrictions, LTIP Payouts and All Other Compensation for each such year.

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Earnings Bonus Unit Plan awards in most recently completed financial year

The following table provides information on earnings bonus units granted in 2006 to the named senior executives. The earnings bonus unit plan is described in more detail on page 46.

Name	Securities Units or Other Rights (#)	Performance or Other Period Until Maturation or Payout (1)	Estimated Future Payouts Under Non-Securities-Price Based Plans Threshold ($)	Target ($)(2)	Maximum ($)(2)
T.J. Hearn	571,400	Nov. 20, 2011	0	1.75	1.75
P.A. Smith	112,700	Nov. 20, 2011	0	1.75	1.75
R.L. Broiles(3)					
R.F. Lipsett	109,200	Nov. 20, 2011	0	1.75	1.75
J.F. Kyle	68,000	Nov. 20, 2011	0	1.75	1.75

(1) Payment will be made earlier when the cumulative net earnings per outstanding common share reach the maximum settlement value per unit prior to the fifth anniversary of the grant date.

(2) This is the maximum settlement value payable per earnings bonus unit granted in 2006.

(3) R.L. Broiles participates in Exxon Mobil Corporation s earnings bonus unit plan which is similar to the

company s earnings bonus unit plan. In 2006, R.L Broiles was granted 37,474 units under that plan for which the maximum settlement value payable per earnings bonus unit is $4.25 U.S.

Aggregated option/SAR exercises during the most recently completed financial year and financial year end option/SAR values

The following table provides information on the exercise in 2006 and the aggregate holdings at the end of 2006 of incentive share units (referred to in the table as SARs) by the named senior executives. The incentive share unit plan is described in more detail on page 45. The number of incentive share units in the table below is equal to three times the number of incentive share units held before the three-for-one share split in May 2006.

Name	Securities Acquired on Exercise (#)	Aggregate Value Realized ($)	Unexercised Options/SARs at Financial Year End (#) Exercisable	Unexercisable (1)	Value of Unexercised in-the-Money Options/SARs at Financial Year End ($) Exercisable	Unexercisable (1)
T.J. Hearn		948,300	90,000	0	2,693,700	0
P.A. Smith		0	135,000	0	4,202,550	0
R.L. Broiles						
R.F. Lipsett		1,103,750	37,500	0	1,122,375	0
J.F. Kyle		0	0	0	0	0

(1) Unexercisable units are units for which the conditions for exercise have not been met.

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The following table provides information on the exercise in 2006 and the aggregate holdings at the end of 2006 of stock options by the named senior executives. The stock option plan is described in more detail on page 46.

	Securities Acquired on Exercise	Aggregate Value Realized	Unexercised Options/SARs at Financial Year End (#) (1)		Value of Unexercised in-the-Money Options/SARs at Financial Year End ($)	
Name	**(#) (1)**	**($)**	**Exercisable**	**Unexercisable (2)**	**Exercisable**	**Unexercisable (2)**
T.J. Hearn	12,000	296,948	165,000	0	4,525,950	0
P.A. Smith	0	0	75,000	0	2,057,250	0
R.L. Broiles (3)						
R.F. Lipsett	0	0	75,000	0	2,057,250	0
J.F. Kyle	30,000	871,083	57,000	0	1,563,510	0

(1) The number for the stock options represents three times the number of stock options granted before the three-for-one share split in May 2006 and still held by the employee.

(2) Unexercisable units are units for which the conditions for exercise have not been met.

(3) At the end of 2006, R.L. Broiles held options to acquire 111,994 Exxon Mobil Corporation shares of which all options were exercisable. The value of R.L.

Broiles exercisable options was $4,390,984 U.S. at the end of 2006. In 2006, R.L. Broiles exercised 11,078 options and realized an aggregate value of $479,265 U.S.

Details of long-term and medium-term incentive compensation

Consistent with the company s compensation philosophy of being performance driven, long-term incentive compensation is granted to retain selected employees and reward them for high performance.

The assessment of employee performance is conducted through the company s appraisal program. The appraisal program is a disciplined annual program that assesses business performance measures relevant to eligible employees and involves ranking of employee performance using a consistent process throughout the organization at all levels. The number of units received by each employee is tied to the performance of the employee in achieving these business performance measures. The scope of the company program is determined by the overall performance of the company each year.

The company s incentive share units give the recipient a right to receive cash equal to the amount by which the market price of the company s common shares at the time of exercise exceeds the issue price of the units. These units were granted prior to 2002. The issue price of the units granted to executives was the closing price of the company s shares on the Toronto Stock Exchange on the grant date. Incentive share units are eligible for exercise up to 10 years from issuance.

In 1998, an additional form of long-term incentive compensation (deferred share units) was made available to selected executives whose decisions are considered to have a direct effect on the long term financial performance of the company. They can elect to receive all or part of their cash bonus compensation in the form of such units. The number of units granted to an executive is determined by dividing the amount of the executive s 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 (average closing price) immediately prior to the date that the bonus would have been paid to the executive. Additional units will be granted to recipients of these units, in respect of unexercised units, based on the cash dividend payable on the company 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. An executive may not exercise these units until after termination of employment with the company and must exercise the units no later than December 31 of the year following termination of employment with the company. The units held must all be exercised on the same date. On the date of exercise, the cash value to be received for the units will be determined by multiplying the number of units exercised by the average closing price immediately prior to the date of exercise. In 2006, no executive elected to receive deferred share units.

Starting in 1999, a form of long-term incentive compensation, similar to the deferred share units for executives, was made available to nonemployee directors in lieu of their receiving all or part of their directors fees. The main differences between the two plans are that all nonemployee directors are allowed to participate in the plan for nonemployee directors and that the number of units granted to a nonemployee director is determined at the end of each calendar quarter by dividing the amount of the directors fees for that calendar quarter that the nonemployee director elected to receive as deferred share units by the average closing price immediately prior to the last day of the calendar quarter.

Starting in 2001, a medium-term incentive compensation plan was introduced, called the earnings bonus unit plan. This plan was made available to selected executives to promote individual contribution to sustained improvement in the company s business performance and shareholder value. Each earnings bonus unit entitles the recipient to receive an amount equal to the company s cumulative net earnings per common share as announced each quarter beginning after the grant. Payout occurs on the fifth anniversary of the grant or when the maximum settlement value per unit is reached, if earlier. If after five years the maximum settlement has not been reached, payout will be prorated.

Under the stock option plan adopted by the company in April 2002, a total of 9,630,600 options, on a post share split basis, were granted to selected key employees on April 30, 2002 for the purchase of the company s common shares at an exercise price of $15.50 per share on a post share split basis. All of the options are exercisable. Any unexercised options expire after April 29, 2012. As of February 15, 2007, there have been 4,139,439 common shares issued upon exercise of stock options and 5,426,811 common shares are issuable upon future exercise of stock options. The common shares that were issued and those that may be issued in the future represent about 1.0 percent of the company s currently outstanding common shares. The company s directors, officers and vice-presidents as a group hold 9.7 percent of the unexercised stock options.

The maximum number of common shares that any one person may receive from the exercise of stock options is 165,000 common shares, which is about 0.02 percent of the currently outstanding common shares. Stock options may be exercised only during employment with the company except in the event of death, disability or retirement. Also, stock options may be forfeited if the company believes that the employee intends to terminate employment or if during employment or during the period of 24 months after the termination of employment the employee, without the consent of the company, engaged in any business that was in competition with the company or otherwise engaged in any activity that was detrimental to the company. The company may determine that stock options will not be forfeited after the cessation of employment. Stock options cannot be assigned except in the case of death.

The company may amend or terminate the incentive stock option plan as it in its sole discretion determines appropriate. No such amendment or termination can be made to impair any rights of stock option holders under the incentive stock option plan unless the stock option holder consents, except in the event of (a) any adjustments to the share capital of the company or (b) a take-over bid, amalgamation, combination, merger or other reorganization, sale or lease of assets, or any liquidation, dissolution, or winding-up, involving the company. Appropriate adjustments may be made by the company to: (i) the number of common shares that may be acquired on the exercise of outstanding stock options; (ii) the exercise price of outstanding stock options; or (iii) the class of shares that may be acquired in place of common shares on the exercise of outstanding stock options in order to preserve proportionately the rights of the stock option holders and give proper effect to the event.

In December 2002, the company introduced a restricted stock unit plan, which will be the primary long-term incentive compensation plan in future years. The purpose of the plan is to align the interests of the selected key employees and nonemployee directors directly with the interests of shareholders. Each unit entitles the recipient the right to receive from the company, upon exercise, an amount equal to the closing price of the company s shares on the exercise dates. Fifty percent of the units will be exercised on the third anniversary of the grant date, and the remainder will be exercised on the seventh anniversary of the grant date. The company will pay the recipients cash with respect to each unexercised unit granted to the recipient corresponding in time and amount to the cash dividend that is paid by the company on a common share of the company. The restricted stock unit plan was amended for units granted in 2002 and future years by providing that the recipient may receive one common share of the company per unit or elect to receive the cash payment for the units to be exercised on the seventh anniversary of the grant date. A total of 1,935,658 units were granted on December 4, 2006.

There are 6,230,974 common shares issuable upon future exercise of restricted stock units, which represent about 0.66 percent of the company s currently outstanding common shares. The company s directors, officers and vice-presidents have available, as a group, 19 percent of the common shares issuable under outstanding restricted stock units. The maximum number of common shares that any one person may receive from the exercise of outstanding restricted stock units is 423,200 common shares, which is about 0.04 percent of the currently outstanding common shares.

Restricted stock units will be exercised only during employment except in the event of death, disability or retirement. Also, restricted stock units may be forfeited if the company believes that the employee intends to terminate employment or if during employment or during the period of 24 months after the termination of employment the employee, without the consent of the company, engaged in any business that was in competition with the company or otherwise engaged in any activity that was detrimental to the company. The company may determine that restricted stock units will not be forfeited after the cessation of employment. Restricted stock units cannot be assigned. In the case of any subdivision, consolidation, or reclassification of the shares of the company or other relevant change in the capitalization of the company, the company, in its discretion, may make appropriate

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adjustments in the number of common shares to be issued and the calculation of the cash amount payable per restricted stock unit. Effective December 31, 2004, the restricted stock unit plan was amended by the company to provide that on retirement the company shall determine whether the employee s restricted stock units will not be forfeited. Effective August 2, 2006, the restricted stock unit plan was amended by the company to change the exercise price under the plan from a single day s closing price to a five-day average and to change exercise dates under the plan from December 31 to December 4 with respect to restricted stock units granted in prior years. Shareholder approval for these changes was not required by the Toronto Stock Exchange.

Payments to Employees Who Retire

Pension Plan Table

Remuneration for determining payments on retirement ($)	**Estimated undiscounted payments on retirement at the age of 65 after years of service indicated below ($)**					
	20 Years	**25 Years**	**30 Years**	**35 Years**	**40 Years**	**45 Years**
100,000	32,000	40,000	48,000	56,000	64,000	72,000
200,000	64,000	80,000	96,000	112,000	128,000	144,000
300,000	96,000	120,000	144,000	168,000	192,000	216,000
400,000	128,000	160,000	192,000	224,000	256,000	288,000
500,000	160,000	200,000	240,000	280,000	320,000	360,000
600,000	192,000	240,000	288,000	336,000	384,000	432,000
800,000	256,000	320,000	384,000	448,000	512,000	576,000
1,000,000	320,000	400,000	480,000	560,000	640,000	720,000
1,500,000	480,000	600,000	720,000	840,000	960,000	1,080,000
2,000,000	640,000	800,000	960,000	1,120,000	1,280,000	1,440,000
2,500,000	800,000	1,000,000	1,200,000	1,400,000	1,600,000	1,800,000
3,000,000	960,000	1,200,000	1,440,000	1,680,000	1,920,000	2,160,000
3,500,000	1,120,000	1,400,000	1,680,000	1,960,000	2,240,000	2,520,000
4,000,000	1,280,000	1,600,000	1,920,000	2,240,000	2,560,000	2,880,000

The company s pension plan applies to almost all employees. The plan provides an annual pension of a specific percentage of an employee s final three year average earnings , multiplied by the employee s years of service, subject to certain requirements concerning age and length of service. An employee may elect to forego three of the six percent of the company s contributions to the savings plan under one of the options of that plan (except for R.L. Broiles), to receive an enhanced pension equal to 0.4 percent of the employee s final three year average earnings , multiplied by the employee s years of service while foregoing such company contributions. In addition to the pension payable under the plan, the company has paid and may continue to pay a supplemental retirement income to employees who have earned a pension in excess of the maximum pension under the Income Tax Act. The pension plan table on this page shows estimated undiscounted annual payments, consisting of pension and supplemental retirement income, payable on retirement to the senior executives in specified classifications of remuneration and years of service currently applicable to that group.

The remuneration used to determine the payments on retirement to the individuals named in the summary compensation table on page 42 corresponds generally to the salary, bonus compensation and bonus compensation amount elected to be received as deferred share units in that table. The aggregate maximum settlement value that could be paid for earnings bonus units granted shown in the table on page 44 is also included in the employee s final three year average earnings for the year of grant of such units. As of February 15, 2007, the number of completed years of service with Imperial Oil Limited used to determine payments on retirement was 40 for T.J. Hearn, 26 for P.A. Smith, 37 for R.F. Lipsett and 30 for J.F. Kyle.

R.L. Broiles is not a member of the company s pension plan, but is a member of Exxon Mobil Corporation s pension plan. Under that plan, R.L. Broiles has 27 years of service and he will receive a pension payable in U.S. dollars. The remuneration used to determine the payment on retirement to him also corresponds generally to his salary extended on a full year basis and bonus compensation in the summary compensation table on page 42, which total may be applied to the pension plan table above but with the dollars in that table representing U.S. rather than Canadian dollars.

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Executive Pension Value Disclosure (1) (2)

Name	Current 2006 Service Cost ($) (3)	Accrued Obligations at Dec. 31, 2006 (4)	Annual Pension Benefit Payable at at age 65 (5)	Age (at Dec. 31, 2006)	Credited Service	Normal Retirement Age
T.J. Hearn	593,000	25,575,000	2,185,400	62	40	65
P.A. Smith	144,100	3,930,000	481,600	53	26	65
R.L. Broiles				49	27	65
R.F. Lipsett	144,200	5,618,000	509,100	60	37	65
J.F. Kyle	91,900	3,706,000	298,900	64	30	65

(1) Pension benefits reflected in these tables do not vest until the named executive officer reaches age 55. In the case of T.J. Hearn, R.F. Lipsett and J.F. Kyle, their accrued pension to date is already vested.

(2) Amounts shown include pension benefits under Imperial Oil Limited s registered pension plan and supplemental retirement plans, other than for R.L. Broiles, who participates in Exxon Mobil Corporation s pension plan and supplemental pension plan. Under Exxon

Mobil Corporation s pension plan and supplemental pension plan, R.L. Broiles current 2006 service cost was $139,963 U.S., the accrued obligations at December 31, 2006 with respect to R.L. Broiles was $1,232,150 U.S. and his annual pension benefit payable at age 65 will be $412,000 U.S.

(3) Service cost is the value of the projected pension for the calendar year 2006. Amounts shown are consistent with disclosure in Note 6 of the 2006 Consolidated Financial Statements.

(4) Accrued obligation is the value of the projected pension earned for service to December 31, 2006. The accrued obligation increases with age and is significantly impacted by changes in the

discount rate. Amounts shown are consistent with disclosure in Note 6 of the 2006 Consolidated Financial Statements.

(5) Amounts in this column are based on current compensation levels and assume accrued years of service to age 65 for each of the named executive officers.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

To the knowledge of the management of the company, the only shareholder who, as of February 15, 2007, owned beneficially, or exercised control or direction over, more than five percent of the outstanding common shares of the company is Exxon Mobil Corporation, 5959 Las Colinas Boulevard, Irving, Texas 75039-2298, which owns beneficially 661,175,328 common shares, representing 69.6 percent of the outstanding voting shares of the company.

Reference is made to the security ownership information under the preceding Items 10 and 11. As of February 15, 2007, R.F. Lipsett was the owner of 4,163 common shares of the company, held options to acquire 75,000 common shares of the company and held 154,650 restricted share units of the company. As of February 15, 2006, J.F. Kyle was the owner of 12,215 common shares of the company, held options to acquire 57,000 common shares of the company and held 127,300 restricted share units of the company.

The directors and the senior executives of the company consist of 10 persons, who, as a group, own beneficially 155,346 common shares of the company, being approximately 0.02 percent of the total number of outstanding shares of the company, and 72,937 shares of Exxon Mobil Corporation. This information not being within the knowledge of the company has been provided by the directors and the senior executives individually. As a group, the directors and senior executives of the company held options to acquire 372,000 common shares of the company and held restricted stock units to acquire 1,196,225 common shares of the company, as of February 15, 2007.

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Equity Compensation Plan Information

The following table provides information on the common shares of the company that may be issued as of the end of 2006 pursuant to compensation plans of the company.

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (3) (a)	Weighted-average exercise price of outstanding options, warrants and rights ($) (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (3) (c)
Equity compensation plans approved by security holders (1)	5,527,665	15.50	0
Equity compensation plans not approved by security holders (2)	6,236,404		4,263,596
Total	11,764,069	15.50	4,263,596

(1) This is a stock option plan, which is described on page 46.

(2) This is a restricted stock unit plan, which is described on page 46 and 47.

(3) The number of securities reserved for the stock option plan represents three times the number of stock options granted before the three-for-one share split in May 2006 and still outstanding. The number of

securities reserved for the restricted stock unit plan represent the securities reserved for restricted stock units issued in 2006 after the three-for-one share split in May 2006, plus three times the number of securities reserved for restricted stock units issued before the share split and still outstanding. The weighted average exercise price of the outstanding stock options of $15.50 was determined on a post share split basis.

Item 13. Certain Relationships and Related Transactions.

On June 23, 2005, the company implemented another 12-month normal course share-purchase program under which it purchased 50,251,542 of its outstanding shares between June 23, 2005 and June 22, 2006. On June 23, 2006, another 12-month normal course program was implemented under which the company may purchase up to 48,772,466 of its outstanding shares, less any shares purchased by the employee savings plan and company pension fund. Exxon Mobil Corporation participated by selling shares to maintain its ownership at 69.6 percent. In 2006, such purchases cost $1,817 million, of which $1,247 million was received by Exxon Mobil Corporation.

During 2003, the company borrowed $818 million from an affiliated company of Exxon Mobil Corporation under two long term loan agreements at interest equivalent to Canadian market rates. Interest on the loans in 2006 was $34 million. The average effective interest rate for the loans was 4.2 percent for 2006.

The amounts of purchases and sales by the company and its subsidiaries for other transactions in 2006 with Exxon Mobil Corporation and affiliates of Exxon Mobil Corporation were $4,292 million and $1,948 million, respectively. These transactions 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, petroleum and chemical products, as well as transportation, technical and engineering services. Transactions with Exxon Mobil Corporation also included amounts paid and received in connection with the company s participation in a number of natural resources activities conducted jointly in Canada. The company has agreements with affiliates of Exxon Mobil Corporation to provide computer and customer support services to the company and to share common business and operational support services to allow the companies to consolidate duplicate work and systems. During 2005, the company and an affiliate of Exxon Mobil Corporation in Canada agreed to operate their respective Western Canada production organizations as one single organization. Under the consolidation, the company will operate all Western Canada properties. There are no asset ownership changes.

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Item 14. Principal Accountant Fees and Services.

Auditor Fees

The aggregate fees of the company s auditors for professional services rendered for the audit of the company s financial statements and other services for the fiscal years ended December 31, 2006 and December 31, 2005 were as follows:

Dollars (thousands)	**2006**	**2005**
Audit Fees	1,117	1,117
Audit-Related Fees	62	64
Tax Fees	815	770
All Other Fees	Nil	Nil
Total Fees	1,994	1,951

Audit fees include the audit of the company s annual financial statements, audit of management s report on internal control over financial reporting, and a review of the first three quarterly financial statements in 2006.

Audit-related fees include other assurance services including the audit of the company s retirement plan and royalty statement audits for oil and gas producing entities.

Tax fees are mainly tax services for employees on foreign loan assignments.

The company did not engage the auditors for any other services.

The audit committee recommends the external auditors to be appointed by the shareholders, fixes their remuneration and oversees their work. The audit committee also approves the proposed current year audit program of the external auditors, assesses the results of the program after the end of the program period and approves in advance any non-audit services to be performed by the external auditors after considering the effect of such services on their independence.

All of the services rendered by the auditors to the company were approved by the audit committee.

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PART IV

Item 15. Exhibits and Financial Statement Schedules.

Reference is made to the Index to Financial Statements on page F-1 of this report.

The following exhibits numbered in accordance with Item 601 of Regulation S-K are filed as part of this report:

(3) (i) Restated certificate and articles of incorporation of the company (Incorporated herein by reference to Exhibit (3.1) to the company s Form 8-K filed on May 3, 2006 (File No. 0-12014)).

(ii) By-laws of the company (Incorporated herein by reference to Exhibit (3)(ii) to the company s Quarterly Report on Form 10-Q for the quarter ended March 31, 2003 (File No. 0-12014)).

(4) The company s long term debt authorized under any instrument does not exceed 10 percent of the company s consolidated assets. The company agrees to furnish to the Commission upon request a copy of any such instrument.

(10) (ii) (1) Alberta Crown Agreement, dated February 4, 1975, relating to the participation of the Province of Alberta in Syncrude (Incorporated herein by reference to Exhibit 13(a) of the company s Registration Statement on Form S-1, as filed with the Securities and Exchange Commission on August 21, 1979 (File No. 2-65290)).

(2) Amendment to Alberta Crown Agreement, dated January 1, 1983 (Incorporated herein by reference to Exhibit (10)(ii)(2) of the company s Annual Report on Form 10-K for the year ended December 31, 1983 (File No. 2-9259)).

(3) Syncrude Ownership and Management Agreement, dated February 4, 1975 (Incorporated herein by reference to Exhibit 13(b) of the company s Registration Statement on Form S-1, as filed with the Securities and Exchange Commission on August 21, 1979 (File No. 2-65290)).

(4) Letter Agreement, dated February 8, 1982, between the Government of Canada and Esso Resources Canada Limited, amending Schedule C to the Syncrude Ownership and Management Agreement filed as Exhibit (10)(ii)(2) (Incorporated herein by reference to Exhibit (20) of the company s Annual Report on Form 10-K for the year ended December 31, 1981 (File No. 2-9259)).

(5) Norman Wells Pipeline Agreement, dated January 1, 1980, relating to the operation, tolls and financing of the pipeline system from the Norman Wells field (Incorporated herein by reference to Exhibit 10(a)(3) of the company s Annual Report on Form 10-K for the year ended December 31, 1981 (File No. 2-9259)).

(6) Norman Wells Pipeline Amending Agreement, dated April 1, 1982 (Incorporated herein by reference to Exhibit (10)(ii)(5) of the company s Annual Report on Form 10-K for the year ended December 31, 1982 (File No. 2-9259)).

(7) Letter Agreement clarifying certain provisions to the Norman Wells Pipeline Agreement, dated August 29, 1983 (Incorporated herein by reference to Exhibit (10)(ii)(7) of the company s Annual Report on Form 10-K for the year ended December 31, 1983 (File No. 2-9259)).

(8) Norman Wells Pipeline Amending Agreement, made as of February 1, 1985, relating to certain amendments ordered by the National Energy Board (Incorporated herein by reference to Exhibit (10)(ii)(8) of the company s Annual Report on Form 10-K for the year ended December 31, 1986 (File No. 0-12014)).

(9) Norman Wells Pipeline Amending Agreement, made as of April 1, 1985, relating to the definition of Operating Year (Incorporated herein by reference to Exhibit (10)(ii)(9) of the company s Annual Report on Form 10-K for the year ended December 31, 1986 (File No. 0-12014)).

(10) Norman Wells Expansion Agreement, dated October 6, 1983, relating to the prices and royalties payable for crude oil production at Norman Wells (Incorporated herein by reference to Exhibit (10)(ii)(8) of the company s Annual Report on Form 10-K for the year

ended December 31, 1983 (File No. 2-9259)).

(11) Alberta Cold Lake Crown Agreement, dated June 25, 1984, relating to the royalties payable and the assurances given in respect of the Cold Lake production project (Incorporated herein by reference to Exhibit (10)(ii)(11) of the company s Annual Report on Form 10-K for the year ended December 31, 1986 (File No. 0-12014)).

(12) Amendment to Alberta Crown Agreement, dated January 1, 1986 (Incorporated herein by reference to Exhibit (10)(ii)(12) of the company s Annual Report on Form 10-K for the year ended December 31, 1987 (File No. 0-12014)).

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(13) Amendment to Alberta Crown Agreement, dated November 25, 1987 (Incorporated herein by reference to Exhibit (10)(ii)(13) of the company s Annual Report on Form 10-K for the year ended December 31, 1987 (File No. 0-12014)).

(14) Amendment to Syncrude Ownership and Management Agreement, dated March 10, 1982 (Incorporated herein by reference to Exhibit (10)(ii)(14) of the company s Annual Report on Form 10-K for the year ended December 31, 1989 (File No. 0-12014)).

(15) Amendment to Alberta Crown Agreement, dated August 1, 1991 (Incorporated herein by reference to Exhibit (10)(ii)(15) of the company s Annual Report on Form 10-K for the year ended December 31, 1991 (File No. 0-12014)).

(16) Norman Wells Settlement Agreement, dated July 31, 1996. (Incorporated herein by reference to Exhibit (10)(ii)(16) of the company s Annual Report on Form 10-K for the year ended December 31, 1996 (File No. 0-12014)).

(17) Amendment to Alberta Crown Agreement, dated January 1, 1997. (Incorporated herein by reference to Exhibit (10)(ii)(17) of the company s Annual Report on Form 10-K for the year ended December 31, 1996 (File No. 0-12014)).

(18) Norman Wells Pipeline Amending Agreement, dated December 12, 1997. (Incorporated herein by reference to Exhibit (10)(ii)(18) of the company s Annual Report on Form 10-K for the year ended December 31, 1998 (File No. 0-12014)).

(19) Norman Wells Pipeline 1999 Amending Agreement, dated May 1, 1999. (Incorporated herein by reference to Exhibit (10)(ii)(19) of the company s Annual Report on Form 10-K for the year ended December 31, 1999 (File No. 0-12014)).

(20) Alberta Cold Lake Transition Agreement, effective January 1, 2000, relating to the royalties payable in respect of the Cold Lake production project and terminating the Alberta Cold Lake Crown Agreement. (Incorporated herein by reference to Exhibit (10)(ii)(20) of the company s Annual Report on Form 10-K for the year ended December 31, 2001 (File No. 0-12014)).

(21) Amendment to Alberta Crown Agreement effective January 1, 2001 (Incorporated herein by reference to Exhibit (10)(ii)(21) of the company s Quarterly Report on Form 10-Q for the quarter ended June 30, 2002 (File No. 0-12014)).

(22) Amendment to Syncrude Ownership and Management Agreement effective January 1, 2001 (Incorporated herein by reference to Exhibit (10)(ii)(22) of the company s Quarterly Report on Form 10-Q for the quarter ended June 30, 2002 (File No. 0-12014)).

(23) Amendment to Syncrude Ownership and Management Agreement effective September 16, 1994 (Incorporated herein by reference to Exhibit (10)(ii)(23) of the company s Quarterly Report on Form 10-Q for the quarter ended June 30, 2002 (File No. 0-12014)).

(24) Amendment to Alberta Crown Agreement dated November 29, 1995 (Incorporated herein by reference to Exhibit (10)(ii)(24) of the company s Quarterly Report on Form 10-Q for the quarter ended June 30, 2002 (File No. 0-12014)).

(iii) (A)(1) Form of Letter relating to Supplemental Retirement Income (Incorporated herein by reference to Exhibit (10)(c)(3) of the company s Annual Report on Form 10-K for the year ended December 31, 1980 (File No. 2-9259)).

(2) Incentive Share Unit Plan and Incentive Share Units granted in 2001 are incorporated herein by reference to Exhibit (10)(iii)(A)(2) of the company s Annual Report on Form 10-K for the year ended December 31, 2001. Units granted in 2000 are incorporated herein by reference to Exhibit (10)(iii)(A)(2) of the company s Annual Report on Form 10-K for the year ended December 31, 2000 (File No. 0-12014); units granted in 1999 are incorporated herein by reference to Exhibit (10)(iii)(A)(3) of the

company s Annual Report on Form 10-K for the year ended December 31, 1999 (File No. 0-12014); units granted in 1998 are incorporated herein by reference to Exhibit (10)(iii)(A)(3) of the company s Annual Report on Form 10-K for the year ended December 31, 1998 (File No. 0-12014); units granted in 1997 are incorporated herein by reference to Exhibit (10)(iii)(A)(3) of the company s Annual Report on Form 10-K for the year ended December 31, 1997 (File No. 0-12014).

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(3) Deferred Share Unit Plan. (Incorporated herein by reference to Exhibit(10)(iii)(A)(5) of the company s Annual Report on Form 10-K for the year ended December 31, 1998 (File No. 0-12014)).

(4) Deferred Share Unit Plan for Nonemployee Directors. (Incorporated herein by reference to Exhibit (10)(iii)(A)(6) of the company s Annual Report on Form 10-K for the year ended December 31, 1998 (File No. 0-12014)).

(5) Form of Earnings Bonus Units (Incorporated herein by reference to Exhibit (10)(iii)(A)(5) of the company s Annual Report on Form 10-K for the year ended December 31, 2003 (File No. 0-12014)) and Earnings Bonus Unit Plan (Incorporated herein by reference to Exhibit (10)(iii)(A)(5) of the company s Annual Report on Form 10-K for the year ended December 31, 2002 (File No. 0-12014)).

(6) Incentive Stock Option Plan and Incentive Stock Options granted in 2002 (Incorporated herein by reference to Exhibit (10)(iii)(A)(6) of the company s Quarterly Report on Form 10-Q for the quarter ended June 30, 2002 (File No. 0-12014)).

(7) Restricted Stock Unit Plan and Restricted Stock Units granted in 2002 (Incorporated herein by reference to Exhibit (10)(iii)(A)(7) of the company s Annual Report on Form 10-K for the year ended December 31, 2002 (File No. 0-12014)).

(8) Restricted Stock Unit Plan and Restricted Stock Units granted in 2003 (Incorporated herein by reference to Exhibit (10)(iii)(A)(8) of the company s Annual Report on Form 10-K for the year ended December 31, 2003 (File No. 0-12014)).

(9) Restricted Stock Unit Plan and general form for Restricted Stock Units, as amended effective December 31, 2004 (Incorporated herein by reference to Exhibit 99.1 of the company s Form 8-K dated December 31, 2004 (File No. 0-12014)).

(10) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2002, as amended effective August 4, 2006 (Incorporated herein by reference to Exhibit 99.10(III)(A)(1) of the company s Quarterly Report on Form 10-Q for the quarter ended September 30, 2006 (File No. 0-12014)).

(11) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2003, as amended effective August 4, 2006 (Incorporated herein by reference to Exhibit 99.10(III)(A)(2) of the company s Quarterly Report on Form 10-Q for the quarter ended September 30, 2006 (File No. 0-12014)).

(12) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2004 and 2005, as amended effective August 4, 2006 (Incorporated herein by reference to Exhibit 99.10(III)(A)(3) of the company s Quarterly Report on Form 10-Q for the quarter ended September 30, 2006 (File No. 0-12014)).

(13) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2006 and subsequent years, as amended effective August 4, 2006 (Incorporated herein by reference to Exhibit 99.10(III)(A)(4) of the company s Quarterly Report on Form 10-Q for the quarter ended September 30, 2006 (File No. 0-12014)).

(14) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2002, as amended effective February 1, 2007 (Incorporated herein by reference to Exhibit 99.1 of the company s Form 8-K filed on February 2, 2007 (File No. 0-121014)).

(21)

Imperial Oil Resources Limited, McColl-Frontenac Petroleum Inc., Imperial Oil Resources N.W.T. Limited and Imperial Oil Resources Ventures Limited, all incorporated in Canada, are wholly-owned subsidiaries of the company. The names of all other subsidiaries of the company are omitted because, considered in the aggregate as a single subsidiary, they would not constitute a significant subsidiary as of December 31, 2006.

(23) (ii) (A) Consent of Independent Registered Public Accounting Firm (PricewaterhouseCoopers LLP).

(31.1) Certification by principal executive officer of Periodic Financial Report pursuant to Rule 13a-14(a).

(31.2) Certification by principal financial officer of Periodic Financial Report pursuant to Rule 13a-14(a).

(32.1) Certification by chief executive officer of Periodic Financial Report pursuant to Rule 13a-14(b) and 18 U.S.C. Section 1350.

(32.2) Certification by chief financial officer of Periodic Financial Report pursuant to Rule 13a-14(b) and 18 U.S.C. Section 1350.

Copies of Exhibits may be acquired upon written request of any shareholder to the investor relations manager, Imperial Oil Limited, 237 Fourth Avenue S.W., Calgary, Alberta, Canada T2P 3M9, and payment of processing and mailing costs.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf on February 27, 2007 by the undersigned, thereunto duly authorized.

Imperial Oil Limited

By /s/ T.J. Hearn

(Timothy J. Hearn, Chairman of the Board, President and Chief Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on February 27, 2007 by the following persons on behalf of the registrant and in the capacities indicated.

Signature	Title
/s/ T.J. Hearn (Timothy J. Hearn)	Chairman of the Board, President, Chief Executive Officer and Director (Principal Executive Officer)
/s/ Paul A. Smith (Paul A. Smith)	Controller and Senior Vice-President, Finance and Administration and Director (Principal Accounting Officer and Principal Financial Officer)
/s/ R.L. Broiles (Randy L. Broiles)	Director
/s/ J.M. Mintz (Jack M. Mintz)	Director
/s/ Roger Phillips (Roger Phillips)	Director
/s/ J.F. Shepard (James F. Shepard)	Director
/s/ Sheelagh D. Whittaker (Sheelagh D. Whittaker)	Director
/s/ V.L. Young (Victor L. Young)	Director

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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, 2006.

Management s assessment of the effectiveness of internal control over financial reporting as of December 31, 2006, was audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

/s/ T.J. Hearn	/s/ Paul A. Smith
T.J. Hearn	P.A. Smith
Chairman, president and chief executive officer	Controller and senior vice-president, finance and administration
	(Principal accounting officer and principal financial officer)

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders of Imperial Oil Limited

We have completed integrated audits of Imperial Oil Limited s consolidated financial statements and of its internal control over financial reporting as of December 31, 2006, in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements

In our opinion, the accompanying consolidated financial statements in the Form 10-K present fairly, in all material respects, the financial position of Imperial Oil Limited and its subsidiaries at December 31, 2006, and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 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, management s assessment, included in the accompanying Management s Report on Internal Control Over Financial Reporting, that the company maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control Integrated Framework* issued by the COSO. The company s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management s assessment and on the effectiveness of the company s internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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

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

/s/ PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta, Canada
February 27, 2007

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Consolidated statement of income

millions of Canadian dollars For the years ended December 31		**2006**	2005	2004
Revenues and other income				
Operating revenues (a)(b)(c)		**24,505**	27,797	22,408
Investment and other income (note 10)(d)		**283**	417	52
Total revenues and other income		**24,788**	28,214	22,460
Expenses				
Exploration		**32**	43	59
Purchases of crude oil and products (b)(e)		**13,793**	17,168	13,094
Production and manufacturing (f)		**3,446**	3,327	2,820
Selling and general		**1,284**	1,577	1,281
Federal excise tax (a)		**1,274**	1,278	1,264
Depreciation and depletion		**831**	895	908
Financing costs (note 14)(g)		**28**	8	7
Total expenses		**20,688**	24,296	19,433
Income before income taxes		**4,100**	3,918	3,027
Income taxes (note 5)		**1,056**	1,318	975
Net income		**3,044**	2,600	2,052
Per-share information (Canadian dollars)				
Net income per common share	basic (note 12)	**3.12**	2.54	1.92
Net income per common share	diluted (note 12)	**3.11**	2.53	1.91
Dividends		**0.32**	0.31	0.29

(a) Operating revenues include federal excise tax of $1,274 million (2005 $1,278 million, 2004 $1,264 million).

(b) Amounts included in operating

revenues for purchase/sale contracts with the same counterparty (associated costs are included in purchases of crude oil and products resulting in no impact to net income) are nil (2005 $4,894 million, 2004 $3,584 million), (note 1).

(c) Operating revenues include amounts from related parties of $1,927 million (2005 $1,325 million, 2004 $1,142 million), (note 15).

(d) Investment and other income include amounts from related parties of $31 million (2005 $24 million, 2004 $23 million), (note 15).

(e) Purchases of crude oil and products include amounts from related parties of $4,119 million (2005 $3,650 million, 2004 $3,169 million), (note 15).

(f) Production and manufacturing expenses include amounts to related parties of $219 million (2005 $175 million, 2004 $43 million), (note 15).

(g) Financing costs include amounts to related parties of $33 million (2005 $22 million, 2004 - $20 million), (note 15).

The information on pages F-7 through F-20 is an integral part of these consolidated financial statements.

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Consolidated statement of cash flows

millions of Canadian dollars Inflow/(outflow) For the years ended December 31	**2006**	2005	2004
Operating activities			
Net income	**3,044**	2,600	2,052
Adjustments for non-cash items:			
Depreciation and depletion	**831**	895	908
(Gain)/loss on asset sales, after tax	**(96)**	(233)	(32)
Deferred income taxes and other	**254**	(116)	(90)
Changes in operating assets and liabilities:			
Accounts receivable	**203**	(414)	(311)
Inventories and prepaids	**(97)**	(67)	(32)
Income taxes payable	**(225)**	304	462
Accounts payable	**(86)**	644	308
All other items net (a)	**(241)**	(162)	47
Cash from operating activities	**3,587**	3,451	3,312
Investing activities			
Additions to property, plant and equipment and intangibles	**(1,177)**	(1,432)	(1,376)
Proceeds from asset sales	**212**	440	102
Loans to equity company			(32)
Cash from (used in) investing activities	**(965)**	(992)	(1,306)
Financing activities			
Short-term debt net	**72**	18	9
Repayment of long-term debt	**(74)**	(21)	(8)
Issuance of common shares under stock option plan	**10**	38	13
Common shares purchased (note 12)	**(1,818)**	(1,795)	(872)
Dividends paid	**(315)**	(317)	(317)
Cash from (used in) financing activities	**(2,125)**	(2,077)	(1,175)
Increase (decrease) in cash	**497**	382	831
Cash at beginning of year	**1,661**	1,279	448
Cash at end of year (b)	**2,158**	1,661	1,279

(a) Includes contribution to registered pension plans of

$395 million (2005 $350 million, 2004 $114 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 F-7 through F-20 is an integral part of these consolidated financial statements.

Consolidated balance sheet

millions of Canadian dollars At December 31	**2006**	2005
Assets		
Current assets		
Cash	**2,158**	1,661
Accounts receivable, less estimated doubtful amounts	**1,871**	2,073
Inventories of crude oil and products (note 13)	**556**	481
Materials, supplies and prepaid expenses	**151**	130
Deferred income tax assets (note 5)	**573**	654
Total current assets	**5,309**	4,999
Investments and other long-term assets	**104**	94
Property, plant and equipment, less accumulated depreciation and depletion (note 3)	**10,457**	10,132
Goodwill (note 3)	**204**	204
Other intangible assets, net	**67**	153
Total assets (note 3)	**16,141**	15,582
Liabilities		
Current liabilities		
Short-term debt	**171**	99
Accounts payable and accrued liabilities (a)	**3,080**	3,170
Income taxes payable	**1,190**	1,399
Current portion of long-term debt (b)	**907**	477
Total current liabilities	**5,348**	5,145
Long-term debt (note 4)(c)	**359**	863
Other long-term obligations (note 7)	**1,683**	1,728
Deferred income tax liabilities (note 5)	**1,345**	1,213
Commitments and contingent liabilities (note 11)		
Total liabilities	**8,735**	8,949
Shareholders equity		
Common shares at stated value (note 12)(d)	**1,677**	1,747
Earnings reinvested	**6,462**	5,466
Accumulated other nonowner changes in equity	**(733)**	(580)
Total shareholders equity	**7,406**	6,633
Total liabilities and shareholders equity	**16,141**	15,582

(a) Accounts payable and accrued liabilities include amounts to related parties of $151 million (2005 $224 million), (note 15).

(b) Current portion of long-term debt includes amounts to related parties of $500 million (2005 - Nil), (note 4).

(c) Long-term debt includes amounts to related parties of $318 million (2005 $818 million), (note 4).

(d) Number of common shares outstanding was 953 million (2005 998 million), (note 12).

The information on pages F-7 through F-20 is an integral part of these consolidated financial statements.

Approved by the directors

/s/ T.J. Hearn	/s/ Paul A. Smith
Chairman, president and chief executive officer	Controller and senior vice-president, finance and administration

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Consolidated statement of shareholders equity

millions of Canadian dollars At December 31	**2006**	2005	2004
Common shares at stated value (note 12)			
At beginning of year	**1,747**	1,801	1,859
Issued under the stock option plan	**10**	38	13
Share purchases at stated value	**(80)**	(92)	(71)
At end of year	**1,677**	1,747	1,801
Earnings reinvested			
At beginning of year	**5,466**	4,889	3,952
Net income for the year	**3,044**	2,600	2,052
Share purchases in excess of stated value	**(1,737)**	(1,703)	(801)
Dividends	**(311)**	(320)	(314)
At end of year	**6,462**	5,466	4,889
Accumulated other nonowner changes in equity			
At beginning of year	**(580)**	(368)	(266)
Minimum pension liability adjustment (note 6)	**580**	(212)	(102)
Post-retirement benefit liability adjustment (note 6)	**(733)**		
At end of year	**(733)**	(580)	(368)
Shareholders equity at end of year	**7,406**	6,633	6,322
Nonowner changes in equity for the year			
Net income for the year	**3,044**	2,600	2,052
Other nonowner changes in equity			
Minimum pension liability adjustment	**580**	(212)	(102)
Post-retirement benefit liability adjustment	**(733)**		
Total nonowner changes in equity for the year	**2,891**	2,388	1,950

The information on pages F-7 through F-20 is an integral part of these consolidated financial statements.

Notes to consolidated financial statements

1. Summary of significant accounting policies

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

The consolidated financial statements have been prepared in accordance with generally accepted accounting principles (GAAP) in the United States of America. The financial statements include certain estimates that reflect management s best judgment. Certain reclassifications to prior years have been made to conform to the 2006 presentation. All amounts are in Canadian dollars unless otherwise indicated.

Principles of consolidation

The consolidated financial statements include the accounts of Imperial Oil Limited and its subsidiaries. Intercompany accounts and transactions are eliminated. Subsidiaries include those companies in which Imperial has both an equity interest and the continuing ability to unilaterally determine strategic, operating, investing and financing policies. Significant subsidiaries included in the consolidated financial statements include Imperial Oil Resources Limited, Imperial Oil Resources N.W.T. Limited, Imperial Oil Resources Ventures Limited and McColl-Frontenac Petroleum Inc. All of the above companies are wholly owned. A significant portion of the company s activities in natural resources is conducted jointly with other companies. The accounts reflect the company s share of undivided interest in such activities, including its 25 percent interest in the Syncrude joint venture and its nine percent interest in the Sable offshore energy project.

Inventories

Inventories are recorded at the lower of cost or net realizable value. The cost of crude oil and products is determined primarily using the last-in, first-out (LIFO) method. LIFO was selected over the alternative first-in, first-out and average cost methods because it provides a better matching of current costs with the revenues generated in the period. Inventory costs include expenditures and other charges, including depreciation, directly or indirectly incurred in bringing the inventory to its existing condition and final storage prior to delivery to a customer. Selling and general expenses are reported as period costs and excluded from inventory costs.

Investments

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

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

Property, plant and equipment

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

The company uses the successful-efforts method to account for its exploration and development activities. Under this method, costs are accumulated on a field-by-field basis with certain exploratory expenditures and exploratory dry holes being expensed as incurred. 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 were 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.

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 commodity prices and foreign-

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currency exchange rates. Annual volumes are based on individual field production profiles, which are also updated annually. Prices for natural gas and other products sold under contract are based on corporate plan assumptions developed annually by major contracts and also for investment evaluation purposes.

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

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 assets begins at the time when production commences on a regular 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 developed reserves. Investments in mining and transportation systems are generally depreciated on a straight-line basis over a 15-year life.

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.

(a) Oil sands are a semi-solid material composed of bitumen, sand, water and clays, which are recovered through surface mining methods. Currently, the company s oil sands production volumes and reserves include the company s share of production volumes and reserves in the Syncrude joint venture.

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.

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

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

Revenues

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

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

Notes to consolidated financial statements (continued)

Effective January 1, 2006, the company adopted the Emerging Issues Task Force (EITF) consensus on Issue No. 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty . The EITF concluded that purchases and sales of inventory with the same counterparty that are entered into in contemplation of one another should be combined and recorded as exchanges measured at the book value of the item sold. In prior periods, the company recorded certain crude oil, natural gas, petroleum product and chemical sales and purchases contemporaneously negotiated with the same counterparty as revenues and purchases. As a result of the EITF consensus, beginning in 2006, the company s accounts operating revenue and purchases of crude oil and products on the consolidated statement of income have been reduced by associated amounts with no impact on net income. All operating segments are affected by this change, with the largest impact in the petroleum products segment.

Share-based compensation

Effective January 1, 2006, the company adopted the Financial Accounting Standards Board s (FASB) revised Statement of Financial Accounting Standards No. 123 (SFAS 123R), Share-based Payment . SFAS 123R requires compensation costs related to share-based payments to be recognized in the income statement over the requisite service period. The amount of the compensation costs is to be measured based on the grant-date fair value of the instrument issued. In addition, liability awards are to be remeasured each reporting period through settlement. SFAS 123R is effective for awards granted or modified after the date of adoption and for awards granted prior to that date that have not vested. In 2003, the company adopted a policy of expensing all share-based payments that is consistent with the provisions of SFAS 123R, and all prior years outstanding stock option awards have vested. SFAS 123R does not materially change the company s existing accounting practices or the amount of share-based compensation recognized in earnings. Compensation expense related to share-based programs is recorded as selling and general expenses in the consolidated statement of income.

The company has recognized restricted stock awards made prior to 2006 in compensation expense using the nominal vesting period approach . Under this method, the fair value of the awards has been amortized into compensation expense over the full vesting period of each award. The fair value is remeasured each reporting period through settlement. For awards granted after the company s adoption of SFAS 123R, compensation expense is recognized using the non-substantive vesting period approach . Under this method, the value of the grants is amortized to compensation expense over the shorter of (a) the vesting period of each award or (b) the remaining time period until the employee becomes retiree eligible. Under both methods, the full unamortized value of awards for employees who retire before the end of the applicable amortization period is expensed. The impact of switching to the non-substantive vesting period approach is not material for the company.

As permitted by Statement of Financial Accounting Standard (SFAS) No. 123, the company continues to apply the intrinsic-value-based method of accounting for the incentive stock options granted in April 2002. Under this method, compensation expense is not recognized on the issuance of stock options, as the exercise price is equal to the market value at the date of grant. If the provisions of SFAS 123 had been adopted for all prior years, net income for 2004 would have been reduced by $2 million. The impact on net income per share on both a basic and diluted basis for 2004 was negligible. All incentive stock options have vested as of January 1, 2005.

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 defined benefit post-retirement plans

In September 2006, the FASB issued 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) . SFAS 158 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 nonowner changes in equity. The standard also requires disclosure in the notes to the financial statements of additional information, including certain effects on net periodic benefit costs of the next fiscal year that arise from delayed recognition of gains or losses and prior service costs. SFAS 158 was adopted by the company in the financial statements for the year ending December 31, 2006. See note 6, Employee retirement benefits, for further details.

3. Business segments

The company operates its business in Canada. The natural resources, petroleum products and chemicals 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 natural resources segment is organized and operates to explore for and ultimately produce crude oil and its equivalent, and natural gas. The petroleum products segment is organized and operates to refine crude oil into petroleum products and the distribution and marketing of these products. The chemicals 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 benefit liability adjustment. Net income in this segment primarily includes financing costs, interest income and incentive compensation expenses.

Segment accounting policies are the same as those described in this summary of significant accounting policies. Natural resources, petroleum products and chemicals expenses include amounts allocated from the corporate and other segment. The allocation is based on a combination of fee for service, proportional segment expenses and a three-year average of capital expenditures. Transfers of assets between segments are recorded at book amounts. Intersegment sales are made essentially at prevailing market prices. Assets and liabilities that are not identifiable by segment are allocated.

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millions of dollars	Natural resources(a) 2006	2005	2004	Petroleum products 2006	2005	2004	Chemicals 2006	2005	2004
Revenues and other income									
External sales (b)	**4,619**	4,702	3,689	**18,527**	21,793	17,503	**1,359**	1,302	1,216
Intersegment sales	**3,837**	3,487	2,891	**2,256**	2,224	1,666	**345**	363	293
Investment and other income	**111**	331	45	**105**	60	42			
	8,567	8,520	6,625	**20,888**	24,077	19,211	**1,704**	1,665	1,509
Expenses									
Exploration	**32**	43	59						
Purchases of crude oil and products	**2,841**	2,837	2,110	**16,178**	19,212	14,769	**1,209**	1,191	1,064
Production and manufacturing	**1,994**	1,931	1,581	**1,266**	1,203	1,064	**189**	195	176
Selling and general (c)	**13**	36	9	**1,018**	1,096	1,043	**76**	81	88
Federal excise tax				**1,274**	1,278	1,264			
Depreciation and depletion	**584**	651	633	**233**	230	257	**11**	12	13
Financing costs (note 14)	**2**		1	**6**	2	2			
Total expenses	**5,466**	5,498	4,393	**19,975**	23,021	18,399	**1,485**	1,479	1,341
Income before income taxes	**3,101**	3,022	2,232	**913**	1,056	812	**219**	186	168
Income taxes (note 5)									
Current	**602**	955	771	**174**	409	314	**60**	69	61
Deferred	**123**	59	(56)	**115**	(47)	(58)	**16**	(4)	(2)
Total income tax expense	**725**	1,014	715	**289**	362	256	**76**	65	59
Net income	**2,376**	2,008	1,517	**624**	694	556	**143**	121	109
Cash flow from (used in) operating activities	**3,024**	2,440	2,331	**507**	799	908	**161**	94	126
Capital and exploration expenditures	**787**	937	1,113	**361**	478	283	**13**	19	15

Property, plant and equipment									
Cost	**14,926**	14,229	13,538	**6,581**	6,350	6,078	**702**	701	682
Accumulated depreciation and depletion	**(8,255)**	(7,780)	(7,337)	**(3,178)**	(3,037)	(2,959)	**(484)**	(474)	(459)
Net property, plant and equipment (d)(e)	**6,671**	6,449	6,201	**3,403**	3,313	3,119	**218**	227	223
Total assets	**7,513**	7,289	6,822	**6,450**	6,257	5,509	**504**	500	490

	Corporate and other			**Eliminations**			**Consolidated**		
millions of dollars	**2006**	2005	2004	**2006**	2005	2004	**2006**	2005	2004
Revenues and other income									
External sales (b)							**24,505**	27,797	22,408
Intersegment sales				**(6,438)**	(6,074)	(4,850)			
Investment and other income	**67**	26	(35)				**283**	417	52
	67	26	(35)	**(6,438)**	(6,074)	(4,850)	**24,788**	28,214	22,460
Expenses									
Exploration							**32**	43	59
Purchases of crude oil and products				**(6,435)**	(6,072)	(4,849)	**13,793**	17,168	13,094
Production and manufacturing				**(3)**	(2)	(1)	**3,446**	3,327	2,820
Selling and general (c)	**177**	364	141				**1,284**	1,577	1,281
Federal excise tax							**1,274**	1,278	1,264
Depreciation and depletion	**3**	2	5				**831**	895	908
Financing costs (note 14)	**20**	6	4				**28**	8	7
Total expenses	**200**	372	150	**(6,438)**	(6,074)	(4,850)	**20,688**	24,296	19,433
Income before income taxes	**(133)**	(346)	(185)				**4,100**	3,918	3,027
Income taxes (note 5)									
Current	**(60)**	(72)	(43)				**776**	1,361	1,103
Deferred	**26**	(51)	(12)				**280**	(43)	(128)
Total income tax expense	**(34)**	(123)	(55)				**1,056**	1,318	975

Net income	**(99)**	(223)	(130)				**3,044**	2,600	2,052
Cash flow from (used in) operating activities	**(105)**	118	(53)				**3,587**	3,451	3,312
Capital and exploration expenditures	**48**	41	34				**1,209**	1,475	1,445
Property, plant and equipment									
Cost	**269**	246	205				**22,478**	21,526	20,503
Accumulated depreciation and depletion	**(104)**	(103)	(101)				**(12,021)**	(11,394)	(10,856)
Net property, plant and equipment (d)(e)	**165**	143	104				**10,457**	10,132	9,647
Total assets	**2,145**	1,959	1,504	**(471)**	(423)	(298)	**16,141**	15,582	14,027

Notes to consolidated financial statements (continued)

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

millions of dollars	**2006**	2005	2004
Total external and intersegment sales	**3,303**	3,687	2,744
Total expenses	**1,966**	1,805	1,598
Net income, after income tax	**1,148**	1,249	780
Total current assets	**516**	245	367
Long-term assets	**4,833**	4,742	4,140
Total current liabilities	**810**	967	948
Other long-term obligations	**344**	382	243
Cash flow from operating activities	**1,229**	1,223	1,211
Cash (used in) investing activities	**(403)**	(403)	(858)

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

millions of dollars	**2006**	2005	2004
Natural resources	**1,936**	1,633	1,360
Petroleum products	**869**	856	1,074
Chemicals	**793**	750	678
Total export sales	**3,598**	3,239	3,112

(c) Consolidated selling and general expenses include delivery costs from final storage areas to customers of $316 million in 2006 (2005 $310 million, 2004 $307 million).

(d) Includes property, plant and equipment under construction of $782 million (2005 - $954 million).

(e) All goodwill has been assigned to the petroleum products segment. There have been no goodwill acquisitions, impairment losses or write-offs due to sales in the past three years.

4. Long-term debt

Issued	Maturity date	Interest rate	**2006**	2005
			Millions of dollars	
2003	$250 million due May 26, 2007 and $250 million due August 26, 2007 (a)	Variable		500
2003	January 19, 2008 (a)	Variable	**318**	318
Long-term debt (b)			**318**	818
Capital leases (c)			**41**	45
Total long-term debt (d) (e)			**359**	863

(a) These are long-term variable-rate loans from an affiliated company of Exxon Mobil Corporation at interest equivalent to Canadian market rates.
(b) The average effective rate for the loans was 4.2 percent for 2006 (2005 2.8 percent).
(c) These obligations primarily relate to the capital lease for marine services, which are provided by the lessor commencing in 2004 for a period of 10 years, extendable for an additional five years. The average imputed rate was 10.7 percent in 2006 (2005 -10.5 percent).
(d) Principal payments on long-term loans of $500 million are due in 2007 and $318 million are due in 2008. Principal payments on capital leases of approximately

$3.6 million a year are due in each of the next five years.

(e) These amounts exclude that portion of long-term debt, totalling $907 million (2005 $477 million), which matures within one year and is included in current liabilities.

5. Income taxes

millions of dollars	**2006**	2005	2004
Current income tax expense	**776**	1,361	1,103
Deferred income tax expense (a)	**280**	(43)	(128)
Total income tax expense (b)	**1,056**	1,318	975
Statutory corporate tax rate (percent)	**32.8**	35.6	37.0
Increase/(decrease) resulting from:			
Non-deductible royalty payments to governments		3.8	3.9
Resource allowance in lieu of royalty deduction		(5.2)	(7.0)
Manufacturing and processing credit			
Enacted tax rate change	**(2.7)**		(1.8)
Other	**(4.3)**	(0.6)	0.1
Effective income tax rate	**25.8**	33.6	32.2

(a) The deferred income tax expense for the year is the difference in net deferred income tax liabilities at the beginning and end of the year. The provisions for deferred income taxes in 2006 include net (charges)/credits for the effect of changes in tax laws and rates of $81 million (2005 nil; 2004 $25 million).

(b) Cash outflow from income taxes, plus investment credits earned, was $1,000 million in 2006 (2005 $1,024 million; 2004 $641 million).

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

millions of dollars	**2006**	2005
Depreciation and amortization	**1,588**	1,470
Successful drilling and land acquisitions	**263**	319
Pension and benefits (a)	**(311)**	(354)
Site restoration	**(161)**	(171)
Net tax loss carryforwards (b)	**(42)**	(49)
Capitalized interest	**50**	26
Other	**(42)**	(28)
Deferred income tax liabilities	**1,345**	1,213
LIFO inventory valuation	**(448)**	(487)
Other	**(125)**	(167)
Deferred income tax assets	**(573)**	(654)
Valuation allowance		
Net deferred income tax liabilities	**772**	559

(a) Income taxes charged directly to shareholders equity related to post-retirement benefit liability adjustment were $66 million benefit in 2006 and those related to minimum pension liability adjustment were $105 million benefit and $41 million benefit in 2005 and 2004, respectively.

(b) Tax losses can be carried

forward
indefinitely.

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

6. Employee retirement benefits

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

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

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

	Pension Benefits		Other post-retirement benefits	
	2006	2005	**2006**	2005
Assumptions used to determine benefit obligations at December 31 (percent)				
Discount rate	**5.25**	5.00	**5.25**	5.00
Long-term rate of compensation increase	**3.50**	3.50	**3.50**	3.50
millions of dollars				
Change in projected benefit obligation				
Projected benefit obligation at January 1	**4,784**	4,260	**458**	436
Current service cost	**100**	86	**8**	7
Interest cost	**238**	239	**23**	24
Amendments		20	**(2)**	
Actuarial loss/(gain)	**(122)**	549	**(19)**	26
Other		(88)		(13)
Benefits paid (a)	**(284)**	(282)	**(27)**	(22)
Projected benefit obligation at December 31	**4,716**	4,784	**441**	458

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Notes to consolidated financial statements (continued)

millions of dollars	Pension Benefits 2006	Pension Benefits 2005	Other post-retirement benefits 2006	Other post-retirement benefits 2005
Accumulated benefit obligation at December 31	**4,207**	4,261		
Change in plan assets				
Fair value at January 1	**3,419**	2,984		
Actual return on plan assets	**514**	370		
Company contributions	**395**	350		
Other		(59)		
Benefits paid (b)	**(239)**	(226)		
Fair value at December 31	**4,089**	3,419		
Plan assets in excess of/(less than) projected benefit obligation at December 31				
Funded plans	**(294)**	(984)		
Unfunded plans	**(333)**	(381)	**(441)**	(458)
Total (c)	**(627)**	(1,365)	**(441)**	(458)

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

Effective December 31, 2006, the company adopted SFAS 158, 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 nonowner changes in equity. In 2006, the amounts recorded in other nonowner changes in equity for net actuarial losses and prior service cost are required by SFAS 158. For 2005, SFAS 87 required an employer to recognize a liability in its balance sheet that was at least equal to the unfunded accumulated benefit obligation for defined benefit pension plans.

	Pension Benefits	Other post-retirement benefits

millions of dollars	**2006**	2005	**2004**	**2006**	2005	2004
Amounts recorded in the consolidated balance sheet consist of:						
Other intangible assets, net		93				
Current liabilities	**(28)**	(24)		**(23)**	(23)	
Other long-term obligations	**(599)**	(818)		**(418)**	(334)	
Total	**(627)**	(749)		**(441)**	(357)	
Cumulative amounts recorded in other nonowner changes in equity consist of:						
Net actuarial loss/(gain)	**947**	875		**73**		
Prior service cost	**74**					
Total	**1,021**	875		**73**		
Assumptions used to determine net periodic benefit cost for years ended December 31 (percent)						
Discount rate	**5.00**	5.75	6.25	**5.00**	5.75	6.25
Long-term rate of compensation increase	**3.50**	3.50	3.50	**3.50**	3.50	3.50
Long-term rate of return on funded assets	**8.25**	8.25	8.25			

millions of dollars						
Components of net periodic benefit cost						
Current service cost	**100**	86	76	**8**	7	6
Interest cost	**238**	239	237	**23**	24	24
Expected return on plan assets	**(299)**	(257)	(223)			
Amortization of prior service cost	**20**	25	27			
Recognized actuarial loss/(gain)	**114**	83	68	**8**	7	4
Net periodic benefit cost	**173**	176	185	**39**	38	34
Changes in amounts recorded in other nonowner changes in equity						
Net actuarial loss/(gain)	**72**	317	143	**73**		
Prior service cost	**74**					

Total recorded in other nonowner changes in equity	**146**	317	143	**73**		
Total recorded in net periodic benefit cost and other nonowner changes in equity, before tax	**319**	493	328	**112**	38	34

Costs for defined contribution plans, primarily the employee savings plan, were $30 million in 2006 (2005 $30 million; 2004 $32 million).

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A summary of the change in other nonowner changes in equity is shown in the table below:

millions of dollars	Total pension and other post-retirement benefits **2006**	2005	2004
(Charge)/credit to accumulated other nonowner changes in equity, before tax	**(219)**	(317)	(143)
Deferred income tax (charge)/credit (note 5)	**66**	105	41
(Charge)/credit to accumulated other nonowner changes in equity, after tax	**(153)**	(212)	(102)

The impact of adopting SFAS 158 is shown in the table below:

millions of dollars	**Pre - SFAS 158 with minimum pension liability adjustment**	**SFAS 158 adoption adjustments**	**Post - SFAS 158**
Other intangible assets, net	73	(6)	67
Total assets	16,147	(6)	16,141
Other long-term obligations	990	693	1,683
Deferred income tax liabilities	1,557	(212)	1,345
Accumulated other nonowner changes in equity	(246)	(487)	(733)
Total liabilities and shareholders equity	16,147	(6)	16,141

Preceding data on 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 8.50 percent in 2007 that declines to 4.50 percent by 2012. 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 2006 long-term expected return of 8.25 percent used in the calculations of pension expense compares to an actual rate of return over the past decade of 9.82 percent.

The company s pension plan asset allocation at December 31, 2005 and 2006, and target allocation for 2007 are as follows:

Asset category (percent)	Target allocation 2007	Percentage of plan assets at December 31 **2006**	2005

Equity securities	50 - 75	**64**	62
Debt securities	25 - 50	**36**	38
Other	0 - 10		

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	**2006**	2005
For funded pension plans with accumulated benefit obligations in excess of plan assets:		
Projected benefit obligation	**375**	4,403
Accumulated benefit obligation	**308**	3,908
Fair value of plan assets	**239**	3,419
Accumulated benefit obligation less fair value of plan assets	**69**	489
For unfunded plans covered by book reserves:		
Projected benefit obligation	**333**	381
Accumulated benefit obligation	**314**	353

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Notes to consolidated financial statements (continued)

Estimated 2007 amortization from accumulated other nonowner changes in equity millions of dollars	Pension benefits	Other post-retirement benefits
Net actuarial loss/(gain) (a)	**76**	6
Prior service cost (b)	**19**	

(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.

Cash flows

Benefit payments expected in:

millions of dollars	Pension benefits	Other post-retirement benefits
2007	245	23
2008	248	24
2009	252	24
2010	257	24
2011	264	24
2012 - 2016	1,465	123

In 2007, the company expects to make cash contributions of about $183 million to its pension plan.

Sensitivities

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

Increase/(decrease)	One percent	One percent

millions of dollars	increase	decrease
Rate of return on plan assets:		
Effect on net benefit cost	(40)	40
Discount rate:		
Effect on net benefit cost	(60)	70
Effect on benefit obligation	(590)	730
Rate of pay increases:		
Effect on net benefit cost	40	(35)
Effect on benefit obligation	185	(150)

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	45	(35)

7. Other long-term obligations

millions of dollars	**2006**	2005
Employee retirement benefits (note 6)(a)	**1,017**	1,152
Asset retirement obligations and other environmental liabilities (b)	**438**	423
Other obligations	**228**	153
Total other long-term obligations	**1,683**	1,728

(a) Total recorded employee retirement benefit obligations also include $51 million in current liabilities (2005 $47 million).

(b) Total asset retirement obligations and other environmental liabilities also include $97 million in

current
liabilities (2005
$76 million).

The change in asset retirement obligations liability is as follows:

millions of dollars	**2006**	2005
Asset retirement obligations liability at January 1	**367**	328
Additions	**61**	53
Accretion	**22**	20
Settlement	**(28)**	(34)
Asset retirement obligations liability at December 31	**422**	367

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8. Derivatives and financial instruments

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

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

9. 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 10 years from issuance. The units may expire earlier if employment is terminated other than by retirement, death or disability.

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

All units require settlement by cash payments with one exception. The restricted stock unit program was amended for units granted in 2002 and future years by providing that the recipient may receive one common share of the company per unit or elect to receive the cash payment for the units to be exercised in the seventh year following the grant date.

In accordance with SFAS 123R, 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, which is the same method of accounting as under SFAS 123. 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 vesting period.
The following table summarizes information about these units for the year ended December 31, 2006:

	Incentive share units (a)	Deferred share units (a)	Restricted stock units (a)
Outstanding at January 1, 2006	10,884,891	138,567	10,556,730
Granted		**6,662**	**1,935,658**
Exercised	**(1,797,141)**	**(60,781)**	**(2,488,047)**
Cancelled or adjusted	**(16,500)**		**(7,951)**
Outstanding at December 31, 2006	**9,071,250**	**84,448**	**9,996,390**

(a) Reflects number of units granted after the share split in 2006, plus the number of units granted prior to the share split in 2006 as adjusted for the share splits that occurred in 1998 and 2006.

The compensation expense charged against income for these programs was $133 million, $238 million and $95 million in 2006, 2005, and 2004, respectively. Total income tax benefit recognized in income related to this compensation expense was $45 million, $127 million and $46 million in 2006, 2005 and 2004, respectively. Cash payments of $162 million, $169 million and $64 million for these programs were made in 2006, 2005 and 2004, respectively.
As of December 31, 2006, there was $265 million of total before-tax unrecognized compensation expenses 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, 2006.

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Notes to consolidated financial statements (continued)

Incentive stock options

In April 2002, incentive stock options were granted for the purchase of the company s common shares at an exercise price of $15.50 per share (adjusted to reflect the three-for-one share split). Up to 50 percent of the options may be exercised on or after January 1, 2003; a further 25 percent may be exercised on or after January 1, 2004; and the remaining 25 percent may be exercised on or after January 1, 2005. Any unexercised options expire after April 29, 2012. The company has not issued incentive stock options since 2002 and has no plans to issue incentive stock options in the future.

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. All incentive stock options have vested as of January 1, 2005.

No compensation expense and no income tax benefit related to stock options were recognized for stock options in 2006, 2005 and 2004. Cash received from stock option exercised in 2006 was $10 million. The aggregate intrinsic value of stock options exercised was $18 million, $43 million and $5 million in 2006, 2005 and 2004, respectively, and for the balance of outstanding stock options is $152 million.

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. The practice is expected to continue.

The following table summarizes information about stock options for the year ended December 31, 2006 :

	Units (a)	Exercise price (dollars) (b)	Remaining contractual term (years)
Incentive stock options			
Outstanding at January 1, 2006	6,135,000	15.50	
Granted			
Exercised	**(628,335)**	**15.50**	
Cancelled or adjusted	**21,000**		
Outstanding at December 31, 2006	**5,527,665**	**15.50**	**5.3**

(a) Reflects number of units granted, as adjusted for any share splits.

(b) Adjusted to reflect the three-for-one share split.

10. Investment and other income

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

millions of dollars	**2006**	2005	2004
Proceeds from asset sales	**212**	440	102
Book value of assets sold	**78**	96	59
Gain/(loss) on asset sales, before tax (a)	**134**	344	43
Gain/(loss) on asset sales, after tax (a)	**96**	233	32

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

11. Commitments and contingent liabilities

At December 31, 2006, the company had commitments for non-cancellable operating leases and other long-term agreements that require the following minimum future payments:

millions of dollars	2007	2008	2009	2010	2011	After 2011
Operating leases (a)	**53**	**51**	**46**	**40**	**35**	**48**
Unconditional purchase obligations (b)	**58**	**58**	**57**	**26**	**26**	**40**
Firm capital commitments (c)	**149**	**11**	**17**	**1**		
Other long-term agreements (d)	**271**	**238**	**164**	**147**	**128**	**240**

(a) Total rental expense incurred for operating leases in 2006 was $79 million (2005 $83 million; 2004 $104 million) which included minimum rental expenditures of $66 million (2005

$63 million; 2004 $77 million). Related rental income was not material.

(b) Unconditional purchase obligations are those long-term commitments that are non-cancellable or cancellable only under certain conditions. These mainly pertain to pipeline throughput agreements. Total payments under unconditional purchase obligations were $100 million in 2006 (2005 $104 million; 2004 $117 million).

(c) Firm capital commitments related to capital projects, shown on an undiscounted basis, totalled approximately $178 million at the end of 2006 (2005 $232 million). Commitments of $136 million were associated with the company s share of upstream capital projects;

the largest commitment of $41 million related to Syncrude.

(d) Other long-term agreements include primarily raw material supply and transportation services agreements. Total payments under other long-term agreements were $441 million in 2006 (2005 $448 million; 2004 $355 million). Payments under other long-term agreements related to the company s share of undivided interest in activities conducted jointly with other companies are approximately $103 million per year.

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

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The company was contingently liable at December 31, 2006, for a maximum of $87 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.

Various lawsuits are pending against Imperial Oil Limited and its subsidiaries. The company accrues an undiscounted liability for those contingencies where the incurrence of a loss is determined to be probable and the amount can be reasonably estimated. Based on a consideration of all relevant facts and circumstances, the company does not believe the ultimate outcome of any currently pending lawsuits against the company will have a material adverse effect on the company s operations or financial condition. There are no events or uncertainties known to management beyond those already included in reported financial information that would indicate a material change in future operating results or financial condition.

12. Common shares

thousands of shares	**As at Dec. 31 2006**	As at Dec. 31 2005
Authorized (prior period data have not been restated)	**1,100,000**	450,000

Effective May 23, 2006, the issued common shares of the company were split on a three-for-one basis and the number of authorized shares was increased from 450 million to 1,100 million. The prior period number of shares outstanding and shares purchased, as well as net income and dividends per share, have been adjusted to reflect the three-for one split.

From 1995 to 2005, the company purchased shares under eleven 12-month normal course share purchase programs, as well as an auction tender. On June 23, 2006, another 12-month normal course share purchase program was implemented with an allowable purchase of 48.8 million shares (five percent of the total at June 21, 2006), less any 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 2004	697,582	6,840
2005	52,527	1,795
2006	**45,514**	**1,818**
Cumulative purchases to date	795,623	10,453

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 retained earnings.

The company s common share activities are summarized below:

	Thousands of shares	Millions of dollars
Balance as at January 1, 2004	1,087,959	1,859
Issued for cash under the stock option plan	822	13

Purchases	(40,821)	(71)
Balance as at December 31, 2004	1,047,960	1,801
Issued for cash under the stock option plan	2,442	38
Purchases	(52,527)	(92)
Balance as at December 31, 2005	997,875	1,747
Issued for cash under the stock option plan	**627**	**10**
Purchases	**(45,514)**	**(80)**
Balance as at December 31, 2006	**952,988**	**1,677**

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

	2006	2005	2004
Net income per common share basic			
Net income (millions of dollars)	**3,044**	2,600	2,052
Weighted average number of common shares outstanding (thousands of shares)	**975,128**	1,024,119	1,070,502
Net income per common share (dollars)	**3.12**	2.54	1.92
Net income per common share diluted			
Net income (millions of dollars)	**3,044**	2,600	2,052
Weighted average number of common shares outstanding (thousands of shares)	**975,128**	1,024,119	1,070,502
Effect of employee stock-based awards (thousands of shares)	**4,460**	4,179	2,454
Weighted average number of common shares outstanding, assuming dilution (thousands of shares)	**979,588**	1,028,298	1,072,956
Net income per common share (dollars)	**3.11**	2.53	1.91

Notes to consolidated financial statements (continued)

13. Miscellaneous financial information

In 2006, net income included an after-tax gain of $14 million (2005 $5 million gain; 2004 $23 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, 2006 by $1,509 million (2005 $1,429 million).

Inventories of crude oil and products at year-end consisted of the following:

million of dollars	**2006**	2005
Crude oil	**211**	174
Petroleum products	**277**	234
Chemical products	**54**	63
Natural gas and other	**14**	10
Total inventories of crude oil and products	**556**	481

Research and development costs in 2006 were $73 million (2005 $68 million; 2004 $70 million) before investment tax credits earned on these expenditures of $7 million (2005 $10 million; 2004 $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 $18 million received from equity investments in 2006 (2005 $21 million; 2004 $18 million).

14. Financing costs

millions of dollars	**2006**	2005	2004
Debt-related interest	**63**	45	37
Capitalized interest	**(48)**	(41)	(34)
Net interest expense	**15**	4	3
Other interest	**13**	4	4
Total financing costs (a)	**28**	8	7

(a) Cash interest payments in 2006 were $71 million (2005 $45 million; 2004 $41 million). The weighted average interest rate on short-term borrowings in 2006 was 4.1 percent (2005 2.7 percent).

15. Transactions with related parties

Revenues and expenses of the company also include the results of transactions with Exxon Mobil Corporation and affiliated companies (ExxonMobil) in the normal course of operations. These were conducted on terms as favourable as they would have been with unrelated parties and primarily consisted of the purchase and sale of crude oil and petroleum and chemical products, as well as transportation, technical and engineering services. Transactions with ExxonMobil also included amounts paid and received in connection with the company s participation in a number of natural resources activities conducted jointly in Canada. The company has existing agreements with affiliates of Exxon Mobil Corporation to provide computer and customer support services to the company and to share common business and operational support services that allow the companies to consolidate duplicate work and systems. The company has a contractual agreement with an affiliate of Exxon Mobil Corporation in Canada to 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 Imperial and ExxonMobil. Imperial and ExxonMobil retain ownership of their respective assets and there is no impact on operations or reserves.

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

The company borrowed $818 million (Cdn) from an affiliated company of Exxon Mobil Corporation under two long-term loan agreements as presented in note 4.

As at December 31, 2006, the company had outstanding loans of $33 million (2005 $32 million) to Montreal Pipe Line Limited, in which the company has an equity interest, for financing of the equity company s capital expenditure programs and working capital requirements.

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16. Net payments/payables to governments

millions of dollars	**2006**	2005	2004
Current income tax expense (note 5)	**776**	1,361	1,103
Federal excise tax	**1,274**	1,278	1,264
Property taxes included in expenses	**100**	99	85
Payroll and other taxes included in expenses	**46**	52	50
GST/QST/HST collected (a)	**2,715**	2,703	2,297
GST/QST/HST input tax credits (a)	**(2,293)**	(2,344)	(1,948)
Other consumer taxes collected for governments	**1,667**	1,613	1,670
Crown royalties	**904**	620	472
Total paid or payable to governments	**5,189**	5,382	4,993
Less investment tax credits and other receipts	**11**	9	14
Net paid or payable to governments	**5,178**	5,373	4,979
Net paid or payable to:			
Federal government	**2,352**	2,736	2,472
Provincial governments	**2,726**	2,538	2,422
Local governments	**100**	99	85
Net paid or payable to governments	**5,178**	5,373	4,979

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