IMPERIAL OIL LTD
Form 10-K
February 28, 2008

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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, 2007 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 ü No......

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 ...... No ü

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 ü No......

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 ü No......

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

Large accelerated filer ü Accelerated filer...... Non-accelerated filer...... Smaller reporting company......

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 ...... No ü

As of the last business day of the 2007 second fiscal quarter, the aggregate market value of the voting stock held by non-affiliates of the registrant was Canadian $13,974,075,595 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 14, 2008, was 900,825,903.

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.

	2007	**2006**	**2005**	**2004**	**2003**
			(dollars)		
Rate at end of period	**1.0120**	0.8582	0.8579	0.8310	0.7738
Average rate during period	**0.9376**	0.8844	0.8276	0.7702	0.7186
High	**1.0908**	0.9100	0.8690	0.8493	0.7738
Low	**0.8437**	0.8528	0.7872	0.7158	0.6349

On February 14, 2008, 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 $1.0033 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)

	2007	2006	2005	2004	2003
External sales (1):			(millions of dollars)		
Natural resources	**4,539**	4,619	4,702	3,689	3,390
Petroleum products	**19,230**	18,527	21,793	17,503	14,710
Chemicals	**1,300**	1,359	1,302	1,216	994
Corporate and other					
	25,069	24,505	27,797	22,408	19,094
Intersegment sales:					
Natural resources	**4,146**	3,837	3,487	2,891	2,224
Petroleum products	**2,305**	2,256	2,224	1,666	1,294
Chemicals	**335**	345	363	293	238
Net income (2):					
Natural resources	**2,369**	2,376	2,008	1,517	1,174
Petroleum products	**921**	624	694	556	462
Chemicals	**97**	143	121	109	44
Corporate and other (3)/eliminations	**(199)**	(99)	(223)	(130)	25
	3,188	3,044	2,600	2,052	1,705
Identifiable assets at December 31 (4):					
Natural resources	**8,171**	7,513	7,289	6,822	6,397
Petroleum products	**6,727**	6,450	6,257	5,509	5,225
Chemicals	**476**	504	500	490	433
Corporate and other/eliminations	**1,251**	1,674	1,536	1,206	282
	16,287	16,141	15,582	14,027	12,337

Capital and exploration expenditures:					
Natural resources	**744**	787	937	1,113	1,007
Petroleum products	**187**	361	478	283	478
Chemicals	**11**	13	19	15	41
Corporate and other	**36**	48	41	34	33
	978	1,209	1,475	1,445	1,559

(1) Export sales are reported in note 3 to the consolidated financial statements on page F-10. Total external sales include $4,894 million for 2005, $3,584 million for 2004, and $2,851 million for 2003 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, and $89 million for 2003. 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, 2007, was as follows:

		2007	**2006**	**2005**	**2004**	**2003**
Conventional (including natural gas liquids):				(thousands a day)		
Barrels	Gross (1)	**45**	55	69	76	74
	Net (2)	**33**	42	54	59	57
Heavy Oil (3):						
Barrels	Gross (1)	**154**	152	139	126	129
	Net (2)	**130**	127	124	112	116
Oil Sands (4):						
Barrels	Gross (1)	**76**	65	53	60	53
	Net (2)	**65**	58	53	59	52
Total:						
Barrels	Gross (1)	**275**	272	261	262	256
	Net (2)	**228**	227	231	230	225

(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 and 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 2004, conventional liquids production increased primarily due to increased natural gas liquids production from the Wizard Lake gas cap. In 2005 and 2006 conventional production fell mainly due to the natural decline of the company s conventional fields. In 2007, the lower production volume was primarily due to decline in the Wizard Lake field. In 2004, Cold Lake production declined due to the timing of steaming cycles and higher royalty, and Syncrude production increased due to improved reliability 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 increased maintenance 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. In 2007, Cold Lake production increased due to timing of steam cycles and production from the ongoing development drilling program and Syncrude production increased with full year operation of the expanded upgrading facilities.

The company s average daily production and sales of natural gas during the five years ended December 31, 2007 are set forth below. All gas volumes in this report are calculated at a pressure base of 14.73 pounds per square inch absolute at 60 degrees Fahrenheit.

	2007	**2006**	**2005**	**2004**	**2003**
			(millions a day)		
Sales (1):					
Cubic feet	**407**	513	536	520	460
Gross Production (2):					
Cubic feet	**458**	556	580	569	513
Net Production (2):					
Cubic feet	**404**	496	514	518	457

(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.

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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. In 2007, the lower production volume was primarily due to decline in production from the gas cap at Wizard Lake.

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

The company s average sales price and production costs for conventional crude oil, Cold Lake heavy oil and natural gas liquids and natural gas for the five years ended December 31, 2007, were as follows:

	2007	**2006**	**2005**	**2004**	**2003**
Average Sales Price:					
Crude oil and natural gas liquids:					
Dollars per barrel	**45.16**	45.13	37.21	32.95	28.92
Natural gas:					
Dollars per thousand cubic feet	**6.95**	7.24	9.00	6.78	6.60
Average Production Costs Per Unit of Net Production (1)(2):					
Dollars per barrel	**12.75**	11.08	10.78	9.25	9.66

(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 and the impact of foreign exchange rates.

Canadian natural gas prices are determined by North American gas markets which are also volatile and the impact of foreign exchange rates. 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 2004, average unit production costs decreased mainly due to higher production from the Wizard Lake gas cap. In 2005, average unit production costs increased mainly due to higher costs of purchased natural gas at Cold Lake. 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. In 2007, unit production costs were higher primarily as a result of lower gas and liquids volumes due to decline in production from Wizard Lake.

The company has interests in a large number of facilities related to the production of crude oil and natural gas. Among these facilities are 21 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 10 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 December 31, 2007, 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	1,139	756	5,090	2,773	6,229	3,529
Heavy Oil wells	4,143	4,143			4,143	4,143

(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 57 percent of the company s net production of conventional crude oil (approximately 63 percent of gross production). In 2007, net production of crude oil and natural gas liquids was about 12,400 barrels per day and gross production was about 18,200 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 540 mile pipeline which transports the crude oil and natural gas liquids from the project. In 2007, 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 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 2007, average net production at Cold Lake was about 130,000 barrels per day and gross production was about 153,500 barrels per day.

To maintain production at Cold Lake, capital expenditures for additional production wells and associated facilities will be required periodically. In 2007, the company spent $307 million and executed a development drilling program of 188 wells on existing phases. In 2008, a development drilling program of more than 100 wells is planned within the approved development area to add productive capacity from undeveloped areas of existing Cold Lake phases. In addition, opportunities are being evaluated to improve utilization of the 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 third-party 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 original 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. Effective January 1, 2000, the company entered into an agreement with the Province of Alberta on a transitional royalty arrangement that applied to all of the company s operations at Cold Lake until the end of 2007 at which time the generic Alberta regulations for heavy oil royalties applied. The transition agreement made 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). The generic regulations which apply effective January 1, 2008, provide for a royalty calculated at the greater of one percent of gross revenue or 25 percent of an amount based on revenue net of operating and capital costs, and with no gas royalty waiver. The transition did not materially change the amount of royalties that the company would have otherwise paid under the pre-existing royalty arrangements. In 2007, the Alberta government proposed increases to the royalty rates beginning in 2009. The company believes that this proposal could have an adverse effect on future company investments in Alberta and the company s future financial results. The magnitude of the potential impact will depend on the final form of enacted legislation and the future prices of oil and gas and cannot be reasonably estimated at this time. The effective royalty on gross production was 15 percent in 2007, 17 percent in 2006, 11 percent in 2005 and 2004 and 10 percent in 2003.

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 totaling about 168,000 leased 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), mines 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 1.8 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 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.

In 2007, the Alberta government proposed changes to the generic oil sands royalty regime beginning in 2009. The Syncrude Joint Venture owners have a Crown Agreement with the Province of Alberta that codifies the royalty rates through December 31, 2015. The Syncrude Joint Venture owners are in discussions with the Alberta government to determine if an amended agreement can be negotiated that would transition Syncrude to the new generic royalty regime before 2016.

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 (located on lease 17) was depleted and ceased operation in 2007. 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 830,000 tons of oil sands a day, producing about 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 sands 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 2007, the upgrading process yielded 0.843 barrels of synthetic crude oil per barrel of crude bitumen. In 2007, about 38 percent of the synthetic crude oil was processed by Edmonton area refineries and the remaining 62 percent was pipelined to refineries in

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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 2007 Syncrude s net production of synthetic crude oil was about 259,300 barrels per day and gross production was about 305,000 barrels per day. The company s share of net production in 2007 was about 64,800 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 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 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 May 1, 2007, the company implemented a management services agreement under which Syncrude will be provided with operational, technical and business management services from Imperial and Exxon Mobil Corporation. The agreement has an initial term of 10 years and may be terminated by the company or Syncrude with at least two years prior written notice.

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

	2007	**2006**	**2005**	**2004**	**2003**
Total mined overburden (1)					
millions of cubic yards	**132.2**	128.2	97.1	100.3	109.2
Mined overburden to oil sands ratio (1)	**1.06**	1.18	1.02	0.94	1.15
Oil sands mined					
millions of tons	**221.0**	195.5	168.0	188.0	168.0
Average bitumen grade (weight percent)	**11.6**	11.4	11.1	11.1	11.0
Crude bitumen in mined oil sands					
millions of tons	**25.6**	22.2	18.6	20.9	18.5
Average extraction recovery (percent)	**91.8**	90.3	89.1	87.3	88.6
Crude bitumen production (2)					
millions of barrels	**132.5**	111.6	94.2	103.3	92.3
Average upgrading yield (percent)	**84.3**	84.9	85.3	85.5	86.0
Gross synthetic crude oil produced					
millions of barrels	**113.0**	95.5	79.3	88.4	78.4
Company s net share (3)					
millions of barrels	**23.7**	21.3	19.3	21.6	19.1

(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 33,400 acres of surface mineable oil sands which forms part of the Kearl project in the Athabasca region of northern Alberta. The company, as operator, filed a regulatory application in July 2005 with the Alberta Energy and Utilities Board for the development of the Kearl oil sands as a joint project with ExxonMobil Canada. The Alberta Energy and Utilities Board and the Government of Canada gave conditional regulatory approval in February 2007 to the company s proposed project, following a joint federal and provincial review. The company, with an approximate 70 percent interest, continues to progress a phased development of the project.

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

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Land Holdings

At December 31, 2007 and 2006, the company held the following oil and gas rights, and heavy oil and oil sands leases:

	Acres					
	Developed		**Undeveloped**		**Total**	
	2007	**2006**	**2007**	**2006**	**2007**	**2006**
Western Provinces			(thousands)			
Conventional						
Gross (1)	**2,529**	2,550	**371**	382	**2,900**	2,932
Net (2)	**995**	1,006	**223**	235	**1,218**	1,241
Heavy Oil						
Gross (1)	**102**	102	**429**	429	**531**	531
Net (2)	**102**	102	**258**	258	**360**	360
Oil Sands						
Gross (1)	**116**	116	**293**	294	**409**	410
Net (2)	**29**	29	**134**	134	**163**	163
Canada Lands (3):						
Conventional						
Gross (1)	**78**	78	**1,302**	794	**1,380**	872
Net (2)	**8**	8	**496**	242	**504**	250
Atlantic Offshore						
Conventional						
Gross (1)	**65**	42	**6,343**	6,425	**6,408**	6,467
Net (2)	**6**	4	**1,513**	1,524	**1,519**	1,528
Total (4):						
Gross (1)	**2,890**	2,888	**8,738**	8,324	**11,628**	11,212
Net (2)	**1,140**	1,149	**2,624**	2,393	**3,764**	3,542

(1) Gross acres include the interests of others.

(2) Net acres exclude the interests of others.

(3) Canada Lands include the Arctic Islands, Beaufort Sea/Mackenzie Delta, and other Northwest Territories, Nunavut and Yukon regions.

(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 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.

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, 2007.

	2007	**2006**	**2005**	**2004**	**2003**
Western and Atlantic Provinces:					
Conventional					
Exploratory					
Oil					
Gas		1		2	3
Dry Holes				1	1
Development					
Oil			2	3	4
Gas	**183**	192	155	207	89
Dry Holes		1	1	1	3
Heavy Oil (Cold Lake and other)					
Development					
Oil	**188**	174	87	218	118
Total	**371**	368	245	432	218

In 2007, 188 heavy oil development wells were drilled to add new productive capacity from undeveloped areas of existing phases at Cold Lake. In addition, 183 gas development wells were drilled in 2007 adding productivity primarily in the shallow gas area. Increased shallow gas development drilling accounted for the increase in gas

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well count in 2004. 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, 2007, the company was participating in the drilling of 183 gross (123 net) exploratory and development wells.

Western Provinces

In 2007, the company had a working interest in 489 gross (371 net) development wells.

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 the largest 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.

In October 2004, the company and its co-venturers filed regulatory applications and environmental impact statements for the project with the National Energy Board (NEB) and other boards, panels and agencies responsible for assessing and regulating energy developments in the Northwest Territories. All the scheduled public hearings by the Joint Review Panel (JRP) and the NEB were concluded in late 2007. The regulatory process continues with a JRP report expected in 2008 followed by an NEB decision in early 2009.

In 2007, the company acquired a 50 percent interest in an exploration licence for about 507,000 gross acres in the Beaufort Sea. As part of the evaluation, a 3-D seismic program is being planned.

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 one exploration licence for about 52,000 gross acres acquired in 1999 in the Sable Island area. One exploratory well was completed on this licence without commercial success. In 2007, one exploration licence in which the company had a 20 percent interest for about 58,000 gross acres in the Sable Island area was allowed to expire.

Also, the company retains a 70 percent interest in one exploration licence for about 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 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. Drilling of an exploration well was concluded in early 2007. Additional drilling is planned.

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

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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 market 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 2007, capital expenditures of about $110 million were made at the company s refineries. About 50 percent of those expenditures were on environmental and safety initiatives with the remaining expenditures being primarily on capacity and efficiency improvements.

The approximate average daily volumes of refinery throughput during the five years ended December 31, 2007, and the daily rated capacities of the refineries at December 31, 2002 and 2007, were as follows:

	Average Daily Volumes of Refinery Throughput (1) Year Ended December 31					**Daily Rated Capacities at December 31 (2)**	
	2007	**2006**	**2005**	**2004**	**2003**	**2007**	**2002**
	(thousands of barrels)						
Strathcona, Alberta	**170**	160	174	170	174	187	184
Sarnia, Ontario	**103**	111	106	108	92	121	121
Dartmouth, Nova Scotia	**69**	77	79	80	82	82	82
Nanticoke, Ontario	**100**	94	108	109	102	112	112
Total	**442**	442	466	467	450	502	499

(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 2007, the same as the previous year but lower than 2005 due to planned and unplanned downtime of crude processing facilities.

Distribution

The company maintains a nation-wide distribution system, including 27 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.

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 1,930 sites of which about 600 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 two 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, 2007, are set out in the following table:

	2007	2006	2005	2004	2003
	(thousands of cubic metres a day)				
Gasolines	**33.1**	32.7	33.4	33.2	33.0
Heating, Diesel and Jet Fuels	**26.0**	26.4	26.9	27.3	26.2
Heavy Fuel Oils	**5.2**	5.1	6.0	5.9	5.4
Lube Oils and Other Products	**6.9**	7.7	7.6	7.0	5.8
Net petroleum product sales	**71.2**	71.9	73.9	73.4	70.4

The total domestic sales of petroleum products as a percentage of total sales of petroleum products during the five years ended December 31, 2007, were as follows:

2007	2006	2005	2004	2003
94.8%	95.1%	95.3%	93.0%	93.3%

The company continues to evaluate and adjust its Esso service station and distribution system to increase productivity and efficiency. During 2007, the company closed or debranded about 80 Esso service stations, about 30 of which were company owned, and added about 50 sites. The company s average annual throughput in 2007 per Esso service station was 3.8 million litres, an increase of about 0.2 million litres from 2006. Average throughput per company owned or leased Esso service station was 6.5 million litres in 2007, an increase of about 0.4 million litres from 2006.

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, 2007, were as follows:

	2007	2006	2005	2004	2003
	(thousands of tonnes a day)				
Petrochemicals	**3.1**	3.0	3.0	3.3	3.3

Research

In 2007, the company s research expenditures in Canada, before deduction of investment tax credits, were $83 million, as compared with $56 million in 2006, and $50 million in 2005. Those funds were used mainly for developing improved heavy oil and oil sands 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 2007. 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 115 people were employed in this type of research and advanced technical support at the end of 2007. Also in Sarnia, there are about 10 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 $1.0 billion on environmental protection and facilities. The environmental expenditures over the past five years primarily reflect spending on two major projects. One project completed in

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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 which cost about $500 million in total. In 2007, the company s capital expenditures relating to environmental protection totaled approximately $135 million which was spent primarily on emissions reductions at Syncrude and company owned facilities as well as on ultra-low sulphur off-road diesel fuel. Capital expenditures relating to environmental protection are expected to be about $200 million in 2008.

Human Resources

At December 31, 2007, the company employed full-time approximately 4,800 persons compared with about 4,900 at the end of 2006 and 5,100 at the end of 2005. About 10 percent of the company s employees are members of unions. The company continues to maintain a broad range of benefits, including health, dental, disability and survivor benefits, vacation, savings plan and pension plan.

Competition

The Canadian petroleum, natural gas and chemical industries are highly competitive. Competition exists in 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 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 2007 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. The acquisition of natural resource properties may, in certain circumstances, be considered to be a transaction that constitutes an acquisition of control of a Canadian business requiring Government of Canada approval.

The Act also 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. 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.

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

In April 2007, the Government of Canada announced its intent to introduce a set of regulations to limit emissions of greenhouse gas and air pollutants from major industrial facilities in Canada beginning in 2010, although the details of the regulations have not been finalized. Consequently, attempts to assess the impact on the company are premature. The company will continue to monitor the development of legal requirements in this area.

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

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

Other 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.

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.

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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 1B Unresolved Staff Comments.

Not applicable.

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

	2007 three months ended				2006 three months ended			
	Mar. 31	**Jun. 30**	**Sep. 30**	**Dec. 31**	**Mar. 31**	**Jun. 30**	**Sep. 30**	**Dec. 31**
Financial data	(millions of dollars)				(millions of dollars)			
Total revenues and other income	**5,934**	**6,339**	**6,430**	**6,740**	5,818	6,688	6,651	5,631
Total expenses	**4,819**	**5,319**	**5,240**	**5,686**	4,928	5,604	5,421	4,735
Income before income taxes	**1,115**	**1,020**	**1,190**	**1,054**	890	1,084	1,230	896
Income taxes	**(341)**	**(308)**	**(374)**	**(168)**	(299)	(247)	(408)	(102)
Net income	**774**	**712**	**816**	**886**	591	837	822	794
Per-share information (a)	(dollars)				(dollars)			
Net earnings basic	**0.82**	**0.76**	**0.88**	**0.97**	0.60	0.85	0.84	0.83
Net earnings diluted	**0.81**	**0.76**	**0.88**	**0.96**	0.59	0.85	0.84	0.83
Dividends (declared quarterly)	**0.08**	**0.09**	**0.09**	**0.09**	0.08	0.08	0.08	0.08
Share prices (a)	(dollars)				(dollars)			
Toronto Stock Exchange								
High	**43.75**	**54.70**	**51.90**	**56.26**	42.28	43.33	45.20	44.80
Low	**37.40**	**41.77**	**40.86**	**45.57**	35.36	36.18	35.33	34.31
Close	**42.80**	**49.59**	**49.29**	**54.26**	41.91	40.78	37.47	42.93
American Stock Exchange	($U.S.)				($U.S.)			
High	**38.29**	**50.35**	**50.95**	**61.48**	36.67	39.64	40.38	38.93
Low	**31.87**	**36.90**	**37.99**	**46.43**	30.54	32.50	31.64	29.99
Close	**37.12**	**46.34**	**49.56**	**54.78**	35.85	36.50	33.55	36.83

(a)

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 14, 2008 there were 13,175 holders of record of common shares of the company.

During the period October 1, 2007 to December 31, 2007, the company issued 164,805 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 2007 (October 1 - October 31)	1,498,890	$ 48.00	1,498,890	30,445,586
November 2007 (November 1 - November 30)	6,656,699	$ 51.45	6,656,699	23,737,240
December 2007 (December 1 - December 31)	2,971,920	$ 51.70	2,971,920	20,714,852

(1) The purchases were pursuant to a 12 month normal course share purchase program that was renewed on June 25, 2007 under which the company may purchase up to 46,459,967 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 24, 2008.

Item 6. Selected Financial Data.

	2007	2006	2005	2004	2003
			(millions of dollars)		

Total operating revenues (a)	**25,069**	24,505	27,797	22,408	19,094
Net income	**3,188**	3,044	2,600	2,052	1,705
Total assets	**16,287**	16,141	15,582	14,027	12,337
Long term debt	**38**	359	863	367	859
Other long term obligations	**1,914**	1,683	1,728	1,525	1,314
			(dollars)		
Net income/share basic (b)	**3.43**	3.12	2.54	1.92	1.53
Net income/share diluted (b)	**3.41**	3.11	2.53	1.91	1.53
Cash dividends/share (b)	**0.35**	0.32	0.31	0.29	0.29

(a) Total operating revenues include $4,894 million for 2005, $3,584 million for 2004, and $2,851 million for 2003 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 business outlook, using a disciplined approach in selecting and pursuing the most attractive investment opportunities. The corporate plan is a fundamental annual management process that is the basis for setting near-term operating and capital objectives, in addition to providing the longer-term economic assumptions used for investment evaluation purposes. Potential investment opportunities are tested over a wide range of economic scenarios to establish the resiliency of each opportunity. Once investments are made, a reappraisal process is completed to ensure relevant lessons are learned and improvements are incorporated into future projects.

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Business environment and risk assessment

Long-term business outlook

Economic and population growth are expected to remain the primary drivers of energy demand, globally and in North America. The company expects the global economy to grow at an average rate of about three percent per year through 2030. The combination of population and economic growth should lead to an increase in demand for primary energy at an average rate of 1.3 percent annually. The vast majority of this increase is expected to occur in developing countries.

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

Over the same period, the Canadian economy is expected to grow at an average rate of about two percent per year, and Canadian demand for energy at less than one percent per year. Oil and gas are expected to continue to supply about two-thirds of Canadian energy demand. It is expected that Canada will also be a growing supplier of energy to U.S. markets through this period.

Oil products are the transportation fuel of choice for the world s fleet of cars, trucks, trains, ships and airplanes. Primarily because of increased demand in developing countries, oil consumption will increase by about 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 30 percent 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.

Natural resources

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

Imperial 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 Canada s North, where Imperial has large undeveloped resource opportunities.

Petroleum products

The downstream industry environment remains very competitive. Refining margins are the difference between what a refinery pays for its raw materials (primarily crude oil) and the wholesale market prices for the range of products produced (primarily gasoline, diesel fuel, heating oil, jet fuel and heavy fuel oil). While refining margins have been strong over the last few years, real inflation adjusted refining margins 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. 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 more than 1,900 Esso-branded service stations, of which about 600 are company-owned or leased, and wholesale and industrial operations through a network of 27 primary distribution terminals, as well as a secondary distribution network.

Chemicals

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 2007 of $3,188 million or $3.41 a share on a diluted basis was the best on record, exceeding the previous record achieved in 2006 of $3,044 million or $3.11 a share. Earnings increased primarily due to higher crude oil commodity prices, stronger industry refining and marketing margins, favourable refinery operations and higher Syncrude volumes. Gains from asset divestments were also higher in 2007. These factors were partially offset by lower expected conventional resources volumes, the negative impact of a stronger Canadian dollar, higher exploration and share-based compensation expenses and higher tax expense.

Natural resources

Net income from natural resources was $2,369 million versus $2,376 million in 2006. Earnings benefited from higher crude oil commodity prices totaling about $325 million and higher Syncrude volumes of about $125 million. Higher gains from asset divestments of about $65 million also contributed to higher earnings. Offsetting these positive factors were lower natural gas, conventional crude oil, and natural gas liquids (NGLs) volumes totaling about $285 million, the negative impact of a stronger Canadian dollar of about $175 million and higher exploration and other operating expenses of about $75 million.

Financial statistics

	2007	**2006**	**2005**	**2004**	**2003**
			(millions of dollars)		
Net income	**2,369**	2,376	2,008	1,517	1,174
Operating revenues	**8,685**	8,456	8,189	6,580	5,584

World crude oil prices, denominated in U.S. dollars, were higher in 2007 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 $72 (U.S.) a barrel in 2007, about 11 percent higher than the average price of $65 in 2006 (2005 $55). 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 $71.70 (Cdn) a barrel, an increase of less than five percent from $68.58 in 2006 (2005 $64.48).

Average realizations for Cold Lake heavy oil in U.S. dollars were about five percent higher for the year. Also mainly because of a stronger Canadian dollar, the company s average realizations for Cold Lake heavy oil were lower by about two percent in 2007.

Prices for Canadian natural gas in 2007 were lower than in the previous year. The average of 30-day spot prices for natural gas in Alberta was about $7.01 a thousand cubic feet in 2007, compared with $7.41 in 2006 (2005 $9.01). The company s average realizations on natural gas sales were $6.95 a thousand cubic feet, compared with $7.24 in 2006 (2005 $9.00).

Average realizations and prices

	2007	**2006**	**2005**	**2004**	**2003**
			(Canadian dollars)		
Conventional crude oil realizations (a barrel)	**71.70**	68.58	64.48	48.96	40.10
Natural gas liquids realizations (a barrel)	**47.92**	40.75	40.00	33.78	32.09
Natural gas realizations (a thousand cubic feet)	**6.95**	7.24	9.00	6.78	6.60
Par crude oil price at Edmonton (a barrel)	**77.67**	73.75	69.86	53.26	43.93
Heavy oil price at Hardisty (Bow River, a barrel)	**53.87**	51.90	45.62	37.98	33.00

Total gross production of crude oil and NGLs averaged 275,000 barrels a day, compared with 272,000 barrels in 2006 (2005 261,000).

Gross production of heavy oil at the company s wholly owned facilities at Cold Lake was a record 154,000 barrels a day, surpassing the previous record of 152,000 barrels in 2006 (2005 139,000). Increased production was 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 2007 with increased volumes from the Stage 3 upgrader expansion. Gross production of synthetic crude oil increased to 305,000 barrels a day from 258,000 barrels in 2006 (2005 214,000). Imperial s share of average gross production increased to 76,000 barrels a day from 65,000 barrels in 2006 (2005 53,000).

Gross production of conventional oil decreased to 29,000 barrels a day from 31,000 barrels in 2006 (2005 38,000) as a result of natural decline in Western Canadian reservoirs and the impact of divested properties.

Gross production of NGLs available for sale averaged 16,000 barrels a day in 2007, down from 24,000 barrels in 2006 (2005 31,000), mainly due to the declining NGL content of Wizard Lake gas production.

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Gross production of natural gas decreased to 458 million cubic feet a day from 556 million in 2006 (2005 580 million). Lower production volumes were primarily due to decline, as expected, in production from the gas cap at Wizard Lake.

In 2007, the company realized a gain of $142 million primarily from the sale of the company s interests in several producing properties. Production of the company s share of these properties averaged about 2,000 oil-equivalent barrels a day in 2006. In 2006, the gain on divestment of assets was approximately $76 million (2005 $208 million).

Crude oil and NGLs production and sales (a)

	2007		**2006**		**2005**		**2004**		**2003**	
	gross	net	gross	net	gross	net	gross	net	gross	net
	(thousands of barrels a day)									
Cold Lake	**154**	**130**	152	127	139	124	126	112	129	116
Syncrude	**76**	**65**	65	58	53	53	60	59	53	52
Conventional crude oil	**29**	**21**	31	23	38	29	43	33	46	35
Total crude oil production	**259**	**216**	248	208	230	206	229	204	228	203
NGLs available for sale	**16**	**12**	24	19	31	25	33	26	28	22
Total crude oil and NGL production	**275**	**228**	272	227	261	231	262	230	256	225
Cold Lake sales, including diluent (b)	**200**		198		183		167		170	
NGL sales	**20**		29		39		42		39	

Natural gas production and sales (a)

	2007		**2006**		**2005**		**2004**		**2003**	
	gross	net	gross	net	gross	net	gross	net	gross	net
	(millions of cubic feet a day)									
Production (c)	**458**	**404**	556	496	580	514	569	518	513	457
Sales	**407**		513		536		520		460	

(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 increased by less than three percent in 2007. Higher exploration and other operating costs were partially offset by lower depreciation expenses.

On May 1, 2007, the company confirmed and implemented a management services agreement with Syncrude Canada Ltd., under which Syncrude will be provided operational, technical and business management services from Imperial and Exxon Mobil Corporation.

Petroleum products

Net income from petroleum products was a record $921 million, $297 million higher than 2006. Increased earnings were primarily due to improved refinery operations including lower refinery maintenance and project activities which contributed about $205 million, and stronger industry refining and marketing margins totaling about $190 million. These positive factors were partially offset by the negative impact of a stronger Canadian dollar of about $60 million and the absence of favourable tax effects of about $40 million.

Financial statistics

	2007	**2006**	**2005**	**2004**	**2003**
			(millions of dollars)		
Net income	**921**	624	694	556	462
Operating revenues (a)	**21,535**	20,783	24,017	19,169	16,004

Sale of petroleum products

	2007	**2006**	**2005**	**2004**	**2003**
			(millions of litres a day (b))		
Gasolines	**33.1**	32.7	33.4	33.2	33.0
Heating, diesel and jet fuels	**26.0**	26.4	26.9	27.3	26.2
Heavy fuel oils	**5.2**	5.1	6.0	5.9	5.4
Lube oils and other products	**6.9**	7.7	7.6	7.0	5.8
Net petroleum product sales	**71.2**	71.9	73.9	73.4	70.4
Total domestic sales of petroleum products (percent)	**94.8**	95.1	95.3	93.0	93.3

Refinery utilization

	2007	2006	2005	2004	2003
		(thousands of barrels a day (b))			
Total refinery throughput (c)	**442**	442	466	467	450
Refinery capacity at December 31	**502**	502	502	502	502
Utilization of total refinery capacity (percent)	**88**	88	93	93	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-7.

(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 are approximately 6.3 barrels.

Margins were stronger in the refining segment of the industry in 2007 compared with those in 2006, pushed up by increased demand for refined petroleum products that stemmed from generally stronger global economic conditions. However, the effects of stronger industry margins were reduced partially by a higher Canadian dollar. Marketing margins in 2007 were slightly higher than those in 2006.

Refinery throughput was 88 percent of capacity in 2007, unchanged from the previous year (2005 - 93 percent). Refinery throughput in 2007 and 2006 was lower than in 2005 due to planned and unplanned downtime of crude processing facilities.

The company s total sales volumes, excluding those resulting from reciprocal supply agreements with other companies, were 71.2 million litres a day, compared with 71.9 million litres in 2006 (2005 73.9 million). Lower refinery production was the main reason for the decline.

Operating costs in 2007 were lower than the previous year by about two percent, reflecting lower maintenance and project related expenses.

Chemicals

Net income from chemicals operations was $97 million, compared with $143 million in 2006. Lower earnings were primarily due to lower industry margins for polyethylene products partially offset by the positive impact of lower tax rates. A stronger Canadian dollar also negatively impacted earnings in 2007.

Financial statistics

	2007	2006	2005	2004	2003
			(millions of dollars)		
Net income	**97**	143	121	109	44
Operating revenues	**1,635**	1,704	1,665	1,509	1,232

Sales

	2007	2006	2005	2004	2003
		(thousands of tonnes a day (a))			
Polymers and basic chemicals	**2.2**	2.2	2.1	2.4	2.4
Intermediate and others	**0.9**	0.8	0.9	0.9	0.9
Total chemicals	**3.1**	3.0	3.0	3.3	3.3

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

The average industry price of polyethylene was $1,666 a tonne in 2007, slightly lower than $1,703 a tonne in 2006 (2005 $1,708).

Sales of chemicals were 3,100 tonnes a day, compared with 3,000 tonnes a day in 2006 (2005 - 3,000 tonnes) primarily due to higher volumes in intermediate chemical products.

Operating costs in the chemicals segment for 2007 were about three percent lower than in 2006, reflecting lower direct operating expenses.

Corporate and other

Net income from corporate and other was negative $199 million, versus negative $99 million last year. Unfavourable earnings effects were primarily due to higher share-based compensation charges and the impact of tax rate changes.

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Liquidity and capital resources
Sources and uses of cash

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

Although the company issues long-term debt from time to time and maintains a revolving commercial paper program, internally generated funds 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.

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

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 $3,626 million, versus $3,587 million in 2006 (2005 - $3,451 million). Higher cash flow in 2007 was primarily due to higher net income. Unfavourable impact of the timing of income tax payments was largely offset by net effects of higher commodity prices on working capital balances.

Cash flow from investing activities

Cash used in investing activities totaled $620 million in 2007, compared with $965 million in 2006 (2005 $992 million). Lower planned spending on property, plant and equipment and higher proceeds from asset sales contributed to the change.

Capital and exploration expenditures

Total capital and exploration expenditures were $978 million in 2007, compared with $1,209 million in 2006 (2005 $1,475 million).

The funds were used mainly to invest in Cold Lake to maintain and expand production capacity, advance upstream projects, invest in environmental initiatives, and upgrade the network of Esso retail outlets. About $160 million was spent on projects related to reducing the environmental impact of the company s operations and improving safety.

The following table shows the company s capital and exploration expenditures for natural resources during the five years ending December 31, 2007:

	2007	2006	2005	2004	2003
			(millions of dollars)		

Heavy oil and oil sands	**489**	518	662	819	769
Production	**150**	237	232	234	181
Exploration	**105**	32	43	60	57
Total capital and exploration expenditures	**744**	787	937	1,113	1,007

For the natural resources segment, over 80 percent of the capital and exploration expenditures in 2007 were focused on growth opportunities. Significant expenditures during the year were made to ongoing development drilling at Cold Lake. Other 2007 investments included advancing the Kearl oil sands and Mackenzie gas projects, drilling at conventional fields in Western Canada, and exploration off the East Coast of Canada. Expenditures at Syncrude were lower in 2007 primarily due to the completion of the Stage 3 upgrader project, partially offset by increased investment in other facility improvement projects and programs.

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The Alberta Energy and Utilities Board and the Government of Canada gave conditional regulatory approval in February 2007 to the company s proposed Kearl oil sands project, following a joint federal and provincial review. The company is advancing the project including further progress in engineering work to define the project design, execution strategies and project cost estimate.

In March, the company, on behalf of the Mackenzie gas project co-venturers, filed updated cost and schedule information on the proposed project with the National Energy Board and Joint Review Panel. The updated project costs are $3.5 billion for the gas-gathering system, $7.8 billion for the Mackenzie Valley Pipeline and $4.9 billion for the development of the anchor fields. Current project activities are focused on regulatory work, finalizing remaining benefits and access agreements and establishing an appropriate fiscal framework with the federal government. All the scheduled public hearings by the Joint Review Panel and the National Energy Board were concluded in late 2007. The regulatory process continues with a Joint Review Panel report expected in 2008 followed by a National Energy Board decision in early 2009.

Drilling of an exploration well with co-venturers in the Orphan Basin off the East Coast of Newfoundland was concluded in April. Exploration costs related to the well were reflected in 2007 earnings. Results from the well will be used to plan future drilling in the area.

During the year, the company, along with co-venturer ExxonMobil Canada, successfully acquired exploration rights for a parcel in the Beaufort Sea. The company s 50 percent share of the proposed exploration spending would be about $293 million with a minimum commitment of about $73 million.

Planned capital and exploration expenditures in natural resources are expected to be about $1,200 million in 2008, with over 80 percent of the total focused on growth opportunities. Investments are mainly planned for development drilling at Cold Lake and conventional oil and gas operations in Western Canada, facilities improvement at Syncrude, the Kearl oil sands project, the Mackenzie gas 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, 2007:

	2007	**2006**	**2005**	**2004**	**2003**
			(millions of dollars)		
Refining and supply	**120**	248	368	178	369
Marketing	**63**	97	91	85	91
Other (a)	**4**	16	19	20	18
Total capital expenditures	**187**	361	478	283	478

(a) Consists primarily of real estate purchases.

For the petroleum products segment, capital expenditures were $187 million in 2007, compared with $361 million in 2006 (2005 $478 million). In 2006, the company completed the project to produce ultra-low sulphur diesel. In 2007, the majority of the capital expenditures were directed to investments to continue enhancements to the company s retail network, environmental and safety initiatives, as well as capacity and efficiency improvements.

Capital expenditures for the petroleum products segment in 2008 are expected to be about $300 million. Major items include investments focused on reducing air emissions and improving refinery utilizations, as well as ongoing upgrades to the retail network.

The following table shows the company s capital expenditures for its chemicals operations during the five years ending December 31, 2007:

	2007	**2006**	**2005**	**2004**	**2003**
			(millions of dollars)		
Capital expenditures	**11**	13	19	15	41

Of the capital expenditures for chemicals in 2007, the major investment focused on operational reliability and energy conservation initiatives.

Planned capital expenditures for chemicals in 2008 will be about $25 million and will include investments to improve safety and increase future feedstock flexibility.

Total capital and exploration expenditures for the company in 2008, which will focus mainly on growth and productivity improvements, are expected to total about $1.5 billion and will be financed from internally generated funds.

Cash flow from financing activities

Cash used in financing activities was $3,956 million in 2007, compared with $2,125 million in 2006 (2005 $2,077 million).

In June, the company renewed the normal course issuer bid (share-repurchase program) for another 12 months. During 2007, the company purchased 50.5 million shares for $2,358 million (2006 45.5 million shares for $1,818 million). Since Imperial initiated its first share-repurchase program in 1995, the company has purchased 846 million shares representing about 48 percent of the total outstanding at the start of the program with resulting distributions to shareholders of $12.8 billion.

The company declared dividends totaling 35 cents a share in 2007, up from 32 cents in 2006 (2005 31 cents). Regular annual per-share dividends paid have increased in each of the past 13 years and, since 1986, payments per share have grown by 97 percent.

During the year, the company retired the entire $818 million of long-term loans and the remaining $404 million of its medium-term notes. Total debt outstanding at the end of 2007, excluding the company s share of equity company debt, was $146 million, compared with $1,437 million at the end of 2006 (2005 $1,439 million). Debt represented two percent of the company s capital structure at the end of 2007, compared with 17 percent at the end of 2006 (2005 18 percent).

Debt-related interest incurred in 2007, before capitalization of interest, was $62 million, compared with $63 million in 2006 (2005 $45 million). The average effective interest rate on the company s debt was 4.9 percent in 2007, compared with 4.4 percent in 2006 (2005 3.1 percent).

Financial percentages and ratios

	2007	**2006**	**2005**	**2004**	**2003**
Total debt as a percentage of capital (a)	**2**	17	18	19	21
Interest coverage ratios					
Earnings basis (b)	**72**	66	88	83	64
Cash-flow basis (c)	**82**	77	101	108	80

(a) Current and long-term portions of debt (page F-5) and the company s share of equity company debt, 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.

Commitments

The following table shows the company s commitments outstanding at December 31, 2007. It combines data from the consolidated balance sheet and from individual notes to the consolidated financial statements.

	Financial Statement Note Reference	**Payment due by period**			
		2008	**2009 to 2012**	**2013 and beyond**	**Total Amount**
			(millions of dollars)		
Long-term debt (a)	Note 4	3	15	23	41
Operating leases (b)	Note 15	55	138	39	232
Unconditional purchase obligations (c)	Note 11	99	345	38	482
Firm capital commitments (d)		250	43	63	356
	Note 6	218	194	601	1,013

Pension and other post-retirement obligations (e)					
Asset retirement obligations (f)	Note 7	33	199	256	488
Other long-term purchase agreements (g)		215	590	200	1,005

(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 are those long-term commitments that are non-cancelable and that third parties have used to secure financing for the facilities that will provide the contracted goods and services. They mainly pertain to pipeline throughput agreements.

(d) Firm capital commitments related to capital projects, shown on an undiscounted basis. The largest commitment outstanding at year-end 2007 was $126 million associated with the company s off-shore exploration projects.

(e) The amount by which the benefit obligations exceeded the fair value of fund assets for pension and other post-retirement plans at year-end. The payments by period include expected contributions to funded pension plans in 2008 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 purchase agreements are non-cancelable, long-term commitments other than unconditional purchase obligations. They include primarily raw material supply and transportation services agreements.

Unrecognized tax benefits totaling $170 million have not been included in the company s commitments table because the company does not expect there will be any cash impact from the final settlements as sufficient funds have been deposited with the Canada Revenue Agency. Further details on the unrecognized tax benefits can be found in note 5 to the financial statements on page F-11.

The company was contingently liable at December 31, 2007, for a maximum of $83 million relating to guarantees for purchasing operating equipment and other assets from its rural marketing associates upon expiry of the associate agreement or the resignation of the associate. The company expects that the fair value of the operating equipment and other assets so purchased would cover the maximum potential amount of future payments under the guarantees.

Litigation and other contingencies

As discussed in note 11 to the consolidated financial statements on page F-18, a variety of claims have been made against Imperial Oil Limited and its subsidiaries. Based on a consideration of all relevant facts and circumstances, the company does not believe the ultimate outcome of any currently pending lawsuits against the company will have a material adverse effect on the company s operations or financial condition.

In 2007, the Alberta government proposed changes to the oil and gas and generic oil sands royalty regime beginning in 2009. The company believes that this proposal could have an adverse effect on future company investments in Alberta and the company s future financial results. The magnitude of the potential impact will depend on the final form of enacted legislation and the future prices of oil and gas and cannot be reasonably estimated at this time. The Syncrude Joint Venture owners have a Crown Agreement with the Province of Alberta that codifies the royalty rates through December 31, 2015. The Syncrude Joint Venture owners are in discussions with the Alberta government to determine if an amended agreement can be negotiated that would transition Syncrude to the new generic oil sands royalty regime before 2016.

Recently issued Statements of Financial Accounting Standards

Fair Value Measurements

In September 2006, the Financial Accounting Standards Board (FASB) issued FASB Statement No. 157 (SFAS 157), Fair Value Measurements. SFAS 157 defines fair value, establishes a framework for measuring fair value when an entity is required to use a fair value measure for recognition or disclosure purposes and expands the disclosures about fair value measurements. SFAS 157 must be adopted by the company no later than January 1, 2008 for all financial assets and liabilities that are measured at fair value and non financial assets and liabilities that are remeasured at fair value at least annually. SFAS 157 must be adopted no later than January 1, 2009 for non financial assets and liabilities that are not remeasured at fair value at least annually. The company does not expect the adoption of SFAS 157 to have a material impact on the company s financial statements.

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 within a well-established, disciplined process driven by senior-level geoscience and engineering professionals (assisted by a central reserves group with significant technical experience), culminating in reviews with and approval by senior management and the company s board of directors. Notably, the company does not use 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 commitments toward the development of the reserves prior to reporting as proved.

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

The year-end 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. The U.S. Securities and Exchange Commission regulations preclude the company from showing in the Financial section of 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 in 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. The quantities shown in the revisions category under heavy oil proved reserves in 2005 and 2006 on page 31 were due mainly to the changes in year-end prices and costs that were used in the determination of reserves.

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

The standardized measure of discounted future cash flows on page 33 is based on the year-end price applied for all future years, as required under Statement of Financial Accounting Standards No. 69 (SFAS 69). Future prices used for any impairment tests will vary from the one used in the SFAS 69 disclosure and could be lower or higher for any given year.

Pension benefits

The company s pension plan is managed in compliance with the requirements of governmental authorities and meets funding levels as determined by independent third-party actuaries. Pension accounting requires explicit assumptions regarding, among others, the discount rate for the benefit obligations, the expected rate of return on plan assets and the long-term rate of future compensation increases. All pension assumptions are reviewed annually by senior management. These assumptions are adjusted only as appropriate to reflect long-term changes in market rates and outlook. The long-term expected rate of return on plan assets of 8.00 percent used in 2007 compares to actual returns of 8.29 percent and 9.84 percent achieved over the last 10- and 20-year periods ending December 31, 2007. 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 and the long-term expected returns are not recorded in pension expense in the year the differences occur. Such differences are deferred, along with other actuarial gains and losses, and are amortized into pension expense over the expected remaining service life of employees. Pension expense represented less than one percent of total expenses in 2007.

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 2007, the obligations were discounted at six percent and the accretion expense was $25 million, before tax, which was significantly less than one percent of total expenses in the year. There would be no material impact on the company s reported financial results if a different discount rate had been used.

Asset retirement obligations are not recognized for assets with an indeterminate useful life. Asset retirement obligations for these facilities generally become firm at the time the facilities are permanently shut down and dismantled. These obligations may include the costs of asset disposal and additional soil remediation. However, these sites have indeterminate lives based on plans for continued operations, and as such, the fair value of the conditional legal obligations cannot be measured, since it is impossible to estimate the future settlement dates of such obligations. For these and non-operating assets, the company accrues provisions for environmental liabilities when it is probable that obligations have been incurred and the amount can be reasonably estimated.

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

Tax Contingencies

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

GAAP requires recognition and measurement of uncertain tax positions that the company has taken or expects to take in its income tax returns. The benefit of an uncertain tax position can only be recognized in the financial statements if management concludes that it is more likely than not that the position will be sustained with the tax authorities. For a position that is likely to be sustained, the benefit recognized in the financial statements is measured at the largest amount that is greater than 50 percent likely of being realized. A reserve is established for the difference between a position taken in an income tax return and the amount recognized in the financial statements. The company s unrecognized tax benefits and a description of open tax years are summarized in note 5 to the consolidated financial statements on page F-11.

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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 April 2007, the Government of Canada announced its intent to introduce a set of regulations to limit emissions of greenhouse gas and air pollutants from major industrial facilities in Canada beginning in 2010, although the details of the regulations have not been finalized. Consequently, attempts to assess the impact on the company are premature. The company will continue to monitor the development of legal requirements in this area.

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

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

Other risks, such as changes in international commodity prices and currency-exchange rates, are beyond the company s control. The company does not use derivative markets to speculate on the future direction of currency or commodity prices and does not sell forward any part of production from any business segment. The company s size, strong financial position and the complementary nature of its natural resources, petroleum products and chemicals segments help mitigate the company s exposure to changes in these other risks. The company s potential exposure to these types of risk is summarized in the earnings sensitivity table below, which shows the estimated annual effect, under current conditions, of certain sensitivities of the company s after-tax net income.

Earnings sensitivities (a)

	millions of dollars after tax	
Nine dollars (U.S.) a barrel change in crude oil prices	+(-)	330
Sixty cents a thousand cubic feet change in natural gas prices	+(-)	6
One cent (U.S) a litre change in sales margins for total petroleum products	+(-)	182
One cent (U.S.) a pound change in sales margins for polyethylene	+(-)	6
Ten 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 2007. Each sensitivity calculation shows the impact on net income that results from a change in one factor, after tax and royalties and holding all other factors constant. While these sensitivities are applicable under current conditions, they may not apply proportionately to larger fluctuations.

The sensitivity of net income to changes in crude oil prices decreased from 2006 year-end by about $8 million (after-tax) for each one U.S.-dollar difference. An increase in the value of the Canadian dollar has lessened the impact of the U.S. dollar denominated crude oil prices on the company s revenues and earnings.

The sensitivity of net income to changes in natural gas prices decreased from 2006 year-end by about $2 million (after-tax) for each 10-cent change, primarily due to the company s lower natural gas production.

The sensitivity of net income to changes in the Canadian dollar versus the U.S. dollar decreased from 2006 year-end by about $4 million (after-tax) for each one-cent difference. This was primarily due to the impact of the widening price spread between light crude oil and Cold Lake heavy oil.

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 50 to 150 feet of overburden, have bitumen grades ranging from 4 to 14 weight percent and ore thickness of 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 400 feet (150 wells per section) and in future mining areas, the well spacing is approximately 1,150 feet (20 wells per section). Proven reserves are within operating North and Aurora mines. In accordance with the long range mine plan approved by the Syncrude owners, there are extractable oil sands in the North and Aurora mines, with average bitumen grades of 10.6 and 11.2 weight percent respectively. After deducting royalties payable to the Province of Alberta, the company estimates its 25 percent net share of proven reserves at year end 2007 was equivalent to 694 million barrels of synthetic crude oil. Imperial s reserve

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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.

In 2007, the Alberta government proposed changes to the generic oil sands royalty regime beginning in 2009. The Syncrude Joint Venture owners have a Crown Agreement with the Province of Alberta that codifies the royalty rates through December 31, 2015. The Syncrude Joint Venture owners are in discussions with the Alberta government to determine if an amended agreement can be negotiated that would transition Syncrude to the new generic royalty regime before 2016.

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

	Synthetic Crude Oil		
	Base mine and North mine	**Aurora mine**	**Total**
	(millions of barrels)		
Beginning of year 2005	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
Revision of previous estimate			
Production	**(11)**	**(13)**	**(24)**
End of year 2007	**188**	**506**	**694**

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

	2007	**2006**	**2005**
	(millions of dollars)		
Sales to customers (1)	**2,383**	2,601	2,739
Intersegment sales (1)(2)	**1,131**	1,251	1,013
	3,514	3,852	3,752
Production expenses	**1,074**	1,016	1,035
Exploration expenses	**100**	32	31
Depreciation and depletion	**371**	467	583
Income taxes	**526**	564	716
Results of operations	**1,443**	1,773	1,387

Capital and exploration expenditures

	2007	2006	2005
		(millions of dollars)	
Property costs (3)			
Proved			
Unproved	**1**		7
Exploration costs	**100**	32	37
Development costs	**437**	496	330
Total capital and exploration expenditures	**538**	528	374

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Property, plant and equipment

	2007	2006
	(millions of dollars)	
Property costs (3)		
Proved	**3,167**	3,226
Unproved	**148**	139
Producing assets	**6,706**	6,392
Support facilities	**180**	184
Incomplete construction	**579**	595
Total cost	**10,780**	10,536
Accumulated depreciation and depletion	**7,505**	7,326
Net property, plant and equipment	**3,275**	3,210

(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.

Oil and Gas Reserves

Proved developed and undeveloped reserves (1)

	Crude oil and natural gas liquids			**Natural Gas**
	Conventional	**Heavy Oil (2)**	**Total**	**Total**
		(millions of barrels)		(billions of cubic feet)
Beginning of year 2005	115	232	347	791
Revisions		350	350	137
Improved recovery				
(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	4	236	240	140
Improved recovery				
(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
Revisions	**24**	**(27)**	**(3)**	**75**
Improved recovery		**6**	**6**	**1**
(Sale)/purchase of reserves in place	**(1)**		**(1)**	**(12)**
Discoveries and extensions		**44**	**44**	**8**
Production	**(12)**	**(47)**	**(59)**	**(147)**
End of year 2007	**82**	**717**	**799**	**635**

(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 above describes changes during the years and balances of proved oil and gas reserves at year-end 2005, 2006 and 2007. 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.

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. We understand that the use of December 31 prices and costs is intended to provide a point in time measure to calculate reserves and to enhance comparability between companies.

The U.S. Securities and Exchange Commission regulations preclude the company from showing in the Financial section of this document, however, 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 in 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. The quantities shown in the revisions category under heavy oil proved reserves in 2005 and 2006 were due mainly to changes in year-end prices and costs that were used in the determination of reserves.

In 2007, the Alberta government proposed increases to the royalty rates on oil and gas production beginning in 2009. The magnitude of the potential impact on future royalty rates will depend on the final form of enacted legislation and the future prices of oil and gas and cannot be reasonably estimated at this time. As a result, this proposed increase in royalty rates cannot be and has not been reflected in the net proved crude oil and natural gas reserves at December 31, 2007.

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 heavy oil, 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.

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)

	2007	**2006**	**2005**	**2004**	**2003**
Crude Oil (millions)					
Conventional					
Barrels	**82**	71	83	115	126
Heavy Oil					
Barrels	**717**	741	551	232	763
Total					
Barrels	**799**	812	634	347	889
Natural Gas (billions)					
Cubic feet	**635**	710	747	791	1,023

(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)

	2007	2006	2005	2004	2003
Crude Oil (millions)					
Conventional					
Barrels	**82**	71	81	111	121
Heavy Oil					
Barrels	**483**	501	368	232	398
Total					
Barrels	**565**	572	449	343	519
Natural Gas (billions)					
Cubic feet	**539**	608	643	704	859

(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 cash flows

As required by SFAS 69, the standardized measure of discounted future net cash flows is computed by applying year-end prices, costs and legislated tax rates and a discount factor of 10 percent to net proved reserves. The standardized measure includes costs for future dismantlement, abandonment and remediation obligations. The company believes the standardized measure does not provide a reliable estimate of the company s expected future cash flows to be obtained from the development and production of its oil and gas properties or of the value of its proved oil and gas reserves. The standardized measure is prepared on the basis of certain prescribed assumptions, including year-end prices, which represent a single point in time and therefore may cause significant variability in cash flows from year to year as prices change. The table below excludes the company s interest in Syncrude.

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

	2007	2006	2005
		(millions of dollars)	
Future cash flows	**32,415**	36,751	21,911
Future production costs	**(14,475)**	(16,290)	(11,376)
Future development costs	**(3,548)**	(2,633)	(2,039)
Future income taxes	**(3,655)**	(5,039)	(2,777)
Future net cash flows	**10,737**	12,789	5,719
Annual discount of 10 percent for estimated timing of cash flows	**(4,487)**	(6,374)	(1,405)
Discounted future cash flows	**6,250**	6,415	4,314

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

	2007	2006	2005

		(millions of dollars)	
Balance at beginning of year	**6,415**	4,314	3,317
Changes resulting from:			
Sales and transfers of oil and gas produced, net of production costs	**(2,430)**	(2,839)	(2,650)
Net changes in prices, development costs and production costs	**(625)**	4,221	3,343
Extensions, discoveries, additions and improved recovery, less related costs	**164**	(4)	(513)
Development costs incurred during the year	**412**	411	272
Revisions of previous quantity estimates	**1,285**	87	660
Accretion of discount	**710**	568	417
Net change in income taxes	**319**	(343)	(532)
Net change	**(165)**	2,101	997
Balance at end of year	**6,250**	6,415	4,314

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 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, 2007. Based on that evaluation, these officers have concluded that the company s disclosure controls and procedures are effective in ensuring that information required to be disclosed by the company in the reports that it files or submits under the Securities Exchange Act of 1934, as amended, is accumulated and communicated to them in a manner that allows for timely decisions regarding required disclosures and are effective in ensuring that such information is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission s rules and forms.

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 the company s internal control over financial reporting as of December 31, 2007.

There has not been any change in the company s internal control over financial reporting during the last fiscal quarter 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 nine directors. Each director is elected to hold office until the close of the next annual meeting.

Each of the eight individuals listed below has been nominated for election at the annual meeting of shareholders to be held May 1, 2008. All of the nominees except for Krystyna T. Hoeg, are now directors and have been since the dates indicated. Timothy J. Hearn and James F. Shepard are currently directors and have both requested not to be nominated for re-election. Timothy J. Hearn has announced his intention to retire as director, chairman and chief executive officer effective March 31, 2008. Bruce H. March has been elected as chairman, president and chief executive officer effective April 1, 2008.

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	
			Deferred share units	7,500
			of Imperial Oil Limited	0
			Restricted stock units of Imperial Oil	0
			Limited	
			Shares of Exxon	66,229
			Mobil Corporation (6)	
Krystyna T. Hoeg Retired president and chief executive officer of Corby Distilleries Limited		Not currently a member of the board	Common shares of Imperial Oil Limited	
			Deferred share units	0
			of Imperial Oil Limited	0
			Restricted stock units of Imperial Oil	0
			Limited	
			Shares of Exxon	0
			Mobil Corporation	
Bruce H. March President, Imperial Oil Limited	Director, refining Europe/Africa/Middle East, ExxonMobil Petroleum & Chemicals, Brussels, Belgium	January 1, 2008	Common shares of	
			Imperial Oil Limited	5,000
			Deferred share units of Imperial Oil	0
			Limited	
			Restricted stock units	0
			of Imperial Oil	
			Limited	70,929

		Shares of Exxon Mobil Corporation (6)	
J.M. (Jack) Mintz Palmer Chair in Public Policy for the University of Calgary (1)(2)	April 21, 2005	Common shares of Imperial Oil Limited	
		Deferred share units of Imperial Oil Limited	1,000
			1,684
		Restricted stock units of Imperial Oil Limited	8,000
		Shares of Exxon Mobil Corporation	0

(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)	
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	14,887
			Restricted stock units of Imperial Oil Limited	12,125
			Shares of Exxon Mobil Corporation	2,000
P.A. (Paul) Smith Senior vice-president, finance and administration, and treasurer Imperial Oil Limited (2)	Controller and senior vice-president, finance and administration	February 1, 2002	Common shares of Imperial Oil Limited	13,337
			Deferred share units of Imperial Oil Limited	0
			Restricted stock units of Imperial Oil Limited	190,250
			Shares of Exxon Mobil Corporation	1,662
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	30,452
			Restricted stock units of Imperial Oil Limited	12,125
			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	5,320
			Restricted stock units of Imperial Oil Limited	12,125
			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 43 and page 44 respectively.

(5) The numbers for the company s restricted stock units and deferred share units represent the total of the restricted stock units and deferred share units received in 2006 and 2007 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 17,729 common shares and 48,500 restricted shares of Exxon Mobil Corporation. B.H. March holds 20,679 common shares and 50,250 restricted shares and restricted stock units 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 50, Timothy J. Hearn 63, Krystyna T. Hoeg 58, Bruce H. March 51, Jack M. Mintz 56, Roger Phillips 68, James F. Shepard 69, Paul A. Smith 54, Sheelagh D. Whittaker 60, Victor L. Young 62 and Brian W. Livingston 53.

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Certain of the directors and nominees for election as directors hold positions as directors of other Canadian and U.S. reporting issuers as follows: Timothy J. Hearn - Royal Bank of Canada; Krystyna T. Hoeg - Sun Life Financial Inc., Shoppers Drug Mart Corporation, Canadian Pacific Railway Limited and Cineplex Galaxy Income Fund; Jack M. Mintz - Brookfield Asset Management Inc. and CHC Helicopter Corporation; Roger Phillips - Canadian Pacific Railway Company, Canadian Pacific Railway Limited, Cleveland-Cliffs Inc. and The Toronto-Dominion Bank; James F. Shepard - Canfor Corporation; 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 Krystyna T. Hoeg, Jack M. Mintz, James F. Shepard 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, Krystyna T. Hoeg was president and chief executive officer of Corby Distilleries Limited until she retired in February 2007, Jack M. Mintz was president and chief executive officer of The C.D. Howe Institute until he retired in July 2006, James F. Shepard became president and chief executive officer of Canfor Corporation in July 2007, 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 as of February 14, 2008.

Name and Office	Office held since
Timothy J. Hearn chairman of the board and chief executive officer	January 1, 2008
Bruce H. March president	January 1, 2008
Paul A. Smith senior vice-president, finance and administration, and treasurer	February 1, 2008
Randy L. Broiles senior vice-president, resources division	July 1, 2005
Brian W. Livingston vice-president, general counsel and corporate secretary	August 1, 2004

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 executive and officer positions, including the chief executive officer. During 2007, 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. Conducted annually, the appraisal process assesses performance against business performance measures and objectives relevant to each employee including the means by which performance is achieved. It 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. Both have been in place for more than 50 years and are 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. The company does not have written employment contracts or any other agreement with its named executive officers providing for payments on change of control or termination of employment.

Base Salary

The company s salary ranges for executives were increased by 2.5 percent in 2006 and 8.0 percent in 2007 and 2008. The salary program in 2008 maintained 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 approximately 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 2007, the overall bonus pool generally remained the same as the previous year and continues to reflect improved financial results and operating performance. In relation to this, the company s net income for 2007 was a record $3.188 billion (up 5 percent), return on shareholders equity was 42 percent, return on capital employed was 38 percent and total annual shareholders return was 28 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 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 2007, 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 2007, similar to the cash bonus pool, the earnings bonus units pool generally remained the same as 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 nonemployee 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 previous 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 in 2006 and 2007 compared to earlier years.

Each unit granted in 2007 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 2007, 800 employees were granted restricted stock units, including 95 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 organization.

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 2007 cash bonus remained the same as his 2006 cash bonus, again 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 the same earnings bonus unit award that he received in 2006 for the same reasons noted above for Mr. Hearn s cash bonus award.

Directors compensation

Directors fees are paid only to nonemployee directors. For 2007, nonemployee directors were paid an annual retainer of $35,000 and 2,000 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 nonemployee directors have the same features as the restricted stock units for selected key employees described on page 44.

Starting in 1999, the nonemployee directors have been able to receive all or part of their directors fees in the form of deferred share units for nonemployee directors. The purpose of the deferred share unit plan for nonemployee 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 43.

While serving as directors in 2007, the aggregate cash remuneration paid to nonemployee directors, as a group, was $384,875, and they received an additional 5,456 deferred share units, based on an aggregate of $265,625 of cash remuneration elected to be received as deferred share units. The nonemployee directors, as a group, received an additional 514 deferred share units granted as the equivalent to the cash dividend paid on company shares during 2007 for previously granted deferred share units. In addition, the nonemployee directors received 10,000 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; the controller and senior vice-president, finance and administration and the three other most highly compensated senior executives of the company who were serving as senior executives at the end of 2007. 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		
Name and Principal Position at the end of 2007	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) ($)	All Other Compensation (8) ($)	Total Compensation (9) ($)
T.J. Hearn Chairman, president and chief executive officer	2007	1,200,000	1,000,050	671,855		130,000 restricted stock units	6,464,900	999,950	36,000	10,372,755
						2 deferred share units	109			
	2006	1,140,000	1,000,050	562,665		130,000 restricted stock units	5,623,800	900,000	34,200	9,260,801
						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	10,720,526
						3 deferred share units	115			
P.A. Smith Controller and	2007	412,500	181,233	125,486		27,200 restricted	1,352,656	197,225	24,750	2,293,850

					stock units				
senior vice-president, finance and administration	2006	404,167	197,267	111,279	35,100 restricted stock units	1,518,426	193,050	24,250	2,448,439
	2005	398,333	193,675	87,198	55,200 restricted stock units	2,123,544	193,125	23,900	3,019,775
R.L. Broiles (1) Senior vice-president,	2007	U.S. 345,000	U.S. 159,000	U.S. 206,336	11,000 restricted shares	U.S. 967,120	U.S. 159,265	U.S. 22,950	U.S. 1,859,671
resources division (from July 1, 2005)	2006	U.S. 325,083	U.S. 159,200	U.S. 421,481	11,000 restricted shares	U.S. 815,760	U.S. 140,513	U.S. 21,705	U.S. 1,883,742
	2005	U.S. 159,000	U.S. 140,500	U.S. 112,214	11,000 restricted shares	U.S. 641,740	U.S. 116,253	U.S. 10,175	U.S. 1,179,882
B.W. Livingston Vice-president,	2007	342,916	157,574	75,274	22,000 restricted stock units	1,094,060	158,900	10,287	1,839,011
general counsel and corporate secretary	2006	318,750	159,088	83,236	22,000 restricted stock units	951,720	153,450	9,562	1,675,806
	2005	303,750	154,330	66,401	33,000 restricted stock units	1,269,510	128,625	9,112	1,931,648
J.F. Kyle Vice-president and treasurer	2007	366,166	122,083	103,405	19,000 restricted stock units	944,870	119,000	21,970	1,677,494
	2006	365,000	119,145	124,081	20,800 restricted stock units	899,808	112,500	21,900	1,642,434
	2005	364,166	112,500	90,821	33,900 restricted stock units	1,304,133	171,375	21,850	2,064,845

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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 ExxonMobil 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 2007, the dividend equivalent payments were $228,476 for T.J. Hearn, $64,476 for P.A. Smith, $38,285 for B.W. Livingston and $42,986 for J.F. Kyle. In 2007, the interest paid in respect of deferred payments of bonuses and earnings bonus units was $335,446 for T.J. Hearn, $6,010 for P.A. Smith, $21,989 for B.W. Livingston and

$30,420 for J.F. Kyle. Also included is an earned benefits allowance. The earned benefits allowance in 2007 was $70,000 for T.J. Hearn, $45,000 for P.A. Smith, $15,000 for B.W. Livingston and $30,000 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 44.

(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 44 and 43 respectively. The number of restricted stock units and deferred share units for 2006 and 2007 are the number of units actually received. The numbers shown for restricted stock units and deferred share units for 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 $38.47 in 2005, $43.26 for 2006 and $49.73 for 2007 (all on a post-split basis). T.J. Hearn is the only senior executive who holds deferred share units and he received additional deferred shares from dividends on his existing deferred shares. The values of the deferred share units shown are the number of such additional deferred share units multiplied by the year-end closing price. R.L. Broiles participates in Exxon Mobil Corporation s restricted stock plan under which the grantee may receive restricted stock or restricted stock units (both of which are referred to herein as restricted stock or restricted shares), which plan is similar to the company s restricted stock unit plan. Under that plan, R.L. Broiles was granted 11,000 restricted shares in 2007, whose value on the date of grant (November 28, 2007) was $967,120 U.S., based on a closing price of Exxon Mobil Corporation shares on the date of grant of $87.92 U.S.

(6) The table below shows the number and value of restricted stock units and deferred share units held as of December 31, 2007. 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 and 2007 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, 2007 was $54.62. 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 48,500 restricted shares whose value on December 31, 2007 was $4,543,965 U.S. based on a closing price for Exxon Mobil Corporation shares on December 31, 2007 of $93.69 U.S.

Restricted Stock Units	Deferred Share Units

Name	Total (#)	Total ($)	Total (#)	Total ($)
T.J. Hearn	714,800	39,042,376	306	16,714
P.A. Smith	190,250	10,391,455	0	0
R.L. Broiles				
B.W. Livingston	119,750	6,540,745	0	0
J.F. Kyle	126,500	6,909,430	0	0

(7) Payouts were from 2006 earnings bonus units that reached maximum value of $1.75 per unit in 2007. That plan is described on page 44. 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 2005, 2006 and 2007 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 2007 to the named senior executives. The earnings bonus unit plan is described in more detail on page 44.

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	444,400	Nov 20, 2012	0	2.25	2.25
P.A. Smith	80,500	Nov 20, 2012	0	2.25	2.25
R.L. Broiles (3)					
B.W. Livingston	70,000	Nov 20, 2012	0	2.25	2.25
J.F. Kyle	54,200	Nov 20, 2012	0	2.25	2.25

(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 2007.

(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 2007, R.L Broiles was granted 31,800 units under that plan for which the maximum settlement value payable per earnings bonus unit is $5.00 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 2007 and the aggregate holdings at the end of 2007 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 43. 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 ($)	Unexercised Options/SARs at Financial Year End (#)		Value of Unexercised in-the-Money Options/SARs at Financial Year End ($)	
			Exercisable	Unexercisable (1)	Exercisable	Unexercisable (1)
T.J. Hearn		2,711,250	0	0	0	0
P.A. Smith		596,100	120,000	0	5,115,900	0
R.L. Broiles						
B.W. Livingston		0	0	0	0	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 2007 and the aggregate holdings at the end of 2007 of stock options by the named senior executives. The stock option plan is described in more detail on page 44.

Name	Securities Acquired on Exercise (#) (1)	Aggregate Value Realized ($)	Unexercised Options/SARs at Financial Year End (#) (1)		Value of Unexercised in-the-Money Options/SARs at Financial Year End ($)	
			Exercisable	Unexercisable (2)	Exercisable	Unexercisable (2)
T.J. Hearn	10,002	296,272	154,998	0	6,063,522	0
P.A. Smith			75,000	0	2,934,000	0
R.L. Broiles (3)						
B.W. Livingston	15,000	512,255	30,000	0	1,173,600	0
J.F. Kyle	57,000	1,790,530	0	0	0	0

(1) The number for the stock options represents three times the number of stock options granted in 2002 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 2007, R. L. Broiles held options to acquire 56,398 Exxon Mobil Corporation

shares of which all options were exercisable. The value of R.L. Broiles exercisable options was $ 2,976,628 U.S. at the end of 2007. In 2007, R.L. Broiles exercised 55,598 options and realized an aggregate value of $ 2,463,063 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 and nonemployee directors 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 2007, 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 select 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 14, 2008, there have been 5,028,645 common shares issued upon exercise of stock options and 4,601,955 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 1.1 percent of the company s currently outstanding common shares. The company s directors, officers and vice-presidents as a group hold 6.8 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 154,998 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 1,713,488 units were granted on December 4, 2007.

There are 7,074,314 common shares issuable upon future exercise of restricted stock units, which represent about 0.79 percent of the company s currently outstanding common shares. The company s directors, officers and vice-presidents have available, as a group, 16 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 488,200 common shares, which is about 0.05 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 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 ($) (1)**					
($)	**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

(1) Payment calculations exclude the effect of integration with CPP/QPP and OAS.

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 40 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 42 is also included in the employee s final three year average earnings for the year of grant of such units. As of February 14, 2008, the number of completed years of service with Imperial Oil Limited used to determine payments on retirement was 41 for T.J. Hearn, 27 for P.A. Smith and 23 for B.W. Livingston. J.F. Kyle retired from the company on January 31, 2008 with 31 completed years of service.

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 28 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 40, 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 2007 Service Cost ($)(3)	Accrued Obligations at Dec. 31, 2007 (4)	Annual Pension Benefit Payable at age 65 (5)	Age (at Dec. 31, 2007)	Credited Service	Normal Retirement Age
T.J. Hearn	515,200	24,482,600	2,144,400	63	41	65
P.A. Smith	133,600	3,624,900	474,000	54	27	65
R.L. Broiles				50	28	65
B.W. Livingston	122,000	2,522,900	382,800	53	23	65
J.F. Kyle	90,100	3,535,400	298,800	64	31	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 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 2007 service cost was $237,418 U.S., the accrued obligations at December 31, 2007 with respect to R.L. Broiles was $1,469,568 U.S. and his annual pension benefit payable at age 65 will be $450,425 U.S.

(3) Service cost is the actuarial value of benefits earned under the pension benefit formula for the calendar year 2007. Amounts shown are consistent with disclosure in Note 6 of the 2007 Consolidated Financial Statements.

(4) Accrued obligation is the value of the projected benefit obligation for pension earned for service to December 31, 2007. 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 2007 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 14, 2008, 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 626,939,795 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 14, 2008, J.F.Kyle was the owner of 12,585 common shares of the company and held 126,500 restricted stock units of the company. As of February 14, 2008, B.W.Livingston was the owner of 5,908 common shares of the company, held options to acquire 30,000 common shares of the company and held 119,750 restricted stock units of the company.

The directors and the senior executives of the company, whose compensation for the year ended December 31, 2007 is described on pages 39 through 41, consist of 11 persons, who, as a group, own beneficially 176,722 common shares of the company, being approximately 0.02 percent of the total number of outstanding shares of the company, and 150,926 shares of Exxon Mobil Corporation (including 98,750 restricted shares). 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 259,998 common shares of the company and held restricted stock units to acquire 827,100 common shares of the company, as of February 14, 2008.

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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 2007 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)	4,728,780	15.50	0
Equity compensation plans not approved by security holders (2)	7,074,314		3,425,686
Total	11,803,094	15.50	3,425,686

(1) This is a stock option plan, which is described on page 44.

(2) This is a restricted stock unit plan, which is described on page 44.

(3) The number of securities reserved for the stock option plan represents three times the number of stock options granted in 2002 before the three-for-one share split in May 2006 and

still outstanding. The number of securities reserved for the restricted stock unit plan represents the securities reserved for restricted stock units issued in 2006 and 2007 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, 2006, the company implemented another 12-month normal course share-purchase program under which it purchased 47,868,663 of its outstanding shares between June 23, 2006 and June 22, 2007. On June 25, 2007, another 12-month normal course program was implemented under which the company may purchase up to 46,459,967 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 2007, such purchases cost $2,358 million, of which $1,615 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 2007 was $33 million. The average effective interest rate for the loans was 4.52 percent for 2007. These loans were repaid in 2007.

The amounts of purchases and sales by the company and its subsidiaries for other transactions in 2007 with Exxon Mobil Corporation and affiliates of Exxon Mobil Corporation were $3,525 million and $1,772 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, natural gas, 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. 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. There are no asset ownership changes. During 2007, the company entered into agreements with Exxon Mobil Corporation and one of its affiliated companies that provide for the delivery of management, business and technical services to Syncrude Canada Ltd. by ExxonMobil.

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Item 14. Principal Accountant Fees and Services.

Auditor Fees

The aggregate fees of the company s auditor for professional services rendered for the audit of the company s financial statements and other services for the fiscal years ended December 31, 2007 and December 31, 2006 were as follows:

Dollars (thousands)	2007	2006
Audit Fees	**1,117**	1,117
Audit-Related Fees	**62**	62
Tax Fees	**942**	815
All Other Fees	**Nil**	Nil
Total Fees	**2,121**	1,994

Audit fees include the audit of the company s annual financial statements and internal control over financial reporting, and a review of the first three quarterly financial statements in 2007.

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 auditor for any other services.

The audit committee recommends the external auditor to be appointed by the shareholders, fixes its remuneration and oversees its work. The audit committee also approves the proposed current year audit program of the external auditor, 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 auditor after considering the effect of such services on their independence.

All of the services rendered by the auditor 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-Q 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).

(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 26, 2008 by the undersigned, thereunto duly authorized.

Imperial Oil Limited

By /s/ T.J. Hearn

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

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on February 26, 2008 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 and Chief Executive Officer and Director (Principal Executive Officer)
/s/ Paul A. Smith (Paul A. Smith)	Senior Vice-President, Finance and Administration, and Treasurer and Director (Principal Accounting Officer and Principal Financial Officer)
/s/ R.L. Broiles (Randy L. Broiles)	Director
/s/ B.H. March (Bruce H. March)	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	Director

(Sheelagh D. Whittaker)	
/s/ V.L. Young	Director
(Victor L. Young)	

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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, 2007.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the company s internal control over financial reporting as of December 31, 2007, as stated in their report which is included herein.

/s/ T.J. Hearn	/s/ Paul A. Smith
T.J. Hearn Chairman and chief executive officer	P.A. Smith Senior vice-president, finance and administration, and treasurer (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 2007, 2006 and 2005 consolidated financial statements and of its internal control over financial reporting as of December 31, 2007. 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, 2007 and December 31, 2006, and the results of their operations and their cash flows for each of the years in the three year period ended December 31, 2007 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

Internal control over financial reporting

Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s report on internal control over financial reporting. Our responsibility is to express an opinion on the effectiveness of the Company s internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

/s/ PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta, Canada
February 26, 2008

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Consolidated statement of income

millions of Canadian dollars For the years ended December 31	**2007**	2006	2005
Revenues and other income			
Operating revenues (a)(b)(c)	**25,069**	24,505	27,797
Investment and other income (note 10)	**374**	283	417
Total revenues and other income	**25,443**	24,788	28,214
Expenses			
Exploration	**106**	32	43
Purchases of crude oil and products (b)(d)	**14,026**	13,793	17,168
Production and manufacturing (e)	**3,474**	3,446	3,327
Selling and general	**1,335**	1,284	1,577
Federal excise tax (a)	**1,307**	1,274	1,278
Depreciation and depletion	**780**	831	895
Financing costs (note 14)(f)	**36**	28	8
Total expenses	**21,064**	20,688	24,296
Income before income taxes	**4,379**	4,100	3,918
Income taxes (note 5)	**1,191**	1,056	1,318
Net income	**3,188**	3,044	2,600
Per-share information (Canadian dollars)			
Net income per common share - basic (note 12)	**3.43**	3.12	2.54
Net income per common share - diluted (note 12)	**3.41**	3.11	2.53
Dividends	**0.35**	0.32	0.31

(a) Operating revenues include federal excise tax of $1,307 million (2006 - $1,274 million, 2005 - $1,278 million).

(b) Operating revenues in 2005 included $4,894 million 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 with no resulting impact on net income, (note 1).

(c) Operating revenues include amounts from related parties of $1,772 million (2006 - $1,955 million, 2005 - $1,346 million), (note 16).

(d) Purchases of crude oil and products include amounts from related parties of $3,331 million (2006 - $3,937 million, 2005 - $3,887 million), (note 16).

(e) Production and manufacturing expenses include amounts to related parties of $194 million (2006 - $156 million, 2005 - $102 million), (note 16).

(f) Financing costs include amounts to related parties of $32 million (2006 - $33 million, 2005 - $22 million), (note 16).

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

Consolidated statement of cash flows

millions of Canadian dollars Inflow/(outflow) For the years ended December 31	**2007**	2006	2005
Operating activities			
Net income	**3,188**	3,044	2,600
Adjustments for non-cash items:			
Depreciation and depletion	**780**	831	895
(Gain)/loss on asset sales, after tax	**(156)**	(96)	(233)
Deferred income taxes and other	**16**	254	(116)
Changes in operating assets and liabilities:			
Accounts receivable	**(261)**	203	(414)
Inventories and prepaids	**13**	(97)	(67)
Income taxes payable	**(77)**	(225)	304
Accounts payable	**250**	(86)	644
All other items - net (a)	**(127)**	(241)	(162)
Cash from operating activities	**3,626**	3,587	3,451
Investing activities			
Additions to property, plant and equipment and intangibles	**(899)**	(1,177)	(1,432)
Proceeds from asset sales	**279**	212	440
Cash from (used in) investing activities	**(620)**	(965)	(992)
Financing activities			
Short-term debt - net	**(65)**	72	18
Repayment of long-term debt	**(1,726)**	(74)	(21)
Long-term debt issued	**500**		
Issuance of common shares under stock option plan	**12**	10	38
Common shares purchased (note 12)	**(2,358)**	(1,818)	(1,795)
Dividends paid	**(319)**	(315)	(317)
Cash from (used in) financing activities	**(3,956)**	(2,125)	(2,077)
Increase (decrease) in cash	**(950)**	497	382
Cash at beginning of year	**2,158**	1,661	1,279
Cash at end of year (b)	**1,208**	2,158	1,661

(a) Includes contribution to registered pension plans of $163 million (2006 - $395 million, 2005 - $350 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.

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Consolidated balance sheet

millions of Canadian dollars At December 31	**2007**	2006
Assets		
Current assets		
Cash	**1,208**	2,158
Accounts receivable, less estimated doubtful amounts	**2,132**	1,871
Inventories of crude oil and products (note 13)	**566**	556
Materials, supplies and prepaid expenses	**128**	151
Deferred income tax assets (note 5)	**660**	573
Total current assets	**4,694**	5,309
Long-term receivables, investments and other long-term assets	**766**	104
Property, plant and equipment, less accumulated depreciation and depletion (note 3)	**10,561**	10,457
Goodwill (note 3)	**204**	204
Other intangible assets, net	**62**	67
Total assets (note 3)	**16,287**	16,141
Liabilities		
Current liabilities		
Short-term debt	**105**	171
Accounts payable and accrued liabilities (a)	**3,335**	3,080
Income taxes payable	**1,498**	1,190
Current portion of long-term debt (b)	**3**	907
Total current liabilities	**4,941**	5,348
Long-term debt (note 4)(c)	**38**	359
Other long-term obligations (note 7)	**1,914**	1,683
Deferred income tax liabilities (note 5)	**1,471**	1,345
Total liabilities	**8,364**	8,735
Commitments and contingent liabilities (note 11)		
Shareholders equity		
Common shares at stated value (note 12)(d)	**1,600**	1,677
Earnings reinvested	**7,071**	6,462
Accumulated other comprehensive income	**(748)**	(733)
Total shareholders equity	**7,923**	7,406
Total liabilities and shareholders equity	**16,287**	16,141

(a) Accounts payable and accrued liabilities include amounts to related parties of $260 million (2006 - $151 million), (note 16).

(b) Current portion of long-term debt in 2006 included $500 million to related parties. There is no current portion of long-term debt to related parties in 2007, (note 4).

(c) Long-term debt in 2006 included $318 million to related parties. There is no long-term debt to related parties in 2007, (note 4).

(d) Number of common shares outstanding was 903 million (2006 - 953 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, and	Senior vice-president,
chief executive officer	finance and administration, and treasurer

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Consolidated statement of shareholders equity

millions of Canadian dollars At December 31	**2007**	2006	200
Common shares at stated value (note 12)			
At beginning of year	**1,677**	1,747	1,80
Issued under the stock option plan	**12**	10	3
Share purchases at stated value	**(89)**	(80)	(9
At end of year	**1,600**	1,677	1,74
Earnings reinvested			
At beginning of year	**6,462**	5,466	4,88
Cumulative effect of accounting change (note 2)	**14**		
Net income for the year	**3,188**	3,044	2,60
Share purchases in excess of stated value	**(2,269)**	(1,737)	(1,70
Dividends	**(324)**	(311)	(32
At end of year	**7,071**	6,462	5,46
Accumulated other comprehensive income			
At beginning of year	**(733)**	(580)	(36
Post-retirement benefits liability adjustment (note 6)	**(87)**	(733)	
Amortization of post-retirement benefits liability adjustment included in net periodic benefit cost	**72**		
Minimum pension liability adjustment (note 6)		580	(21
At end of year	**(748)**	(733)	(58
Shareholders equity at end of year	**7,923**	7,406	6,63
Comprehensive income for the year			
Net income for the year	**3,188**	3,044	2,60
Post-retirement benefits liability adjustment (note 18)	**(15)**		
Minimum pension liability adjustment (note 18)		334	(21
Total comprehensive income for the year	**3,173**	3,378	2,38

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

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Notes to consolidated financial statements

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

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

The consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America. The financial statements include certain estimates that reflect management s best judgment. Certain reclassifications to prior years have been made to conform to the 2007 presentation. All amounts are in Canadian dollars unless otherwise indicated.

1. Summary of significant accounting policies

Principles of consolidation

The consolidated financial statements include the accounts of Imperial Oil Limited and its subsidiaries. Intercompany accounts and transactions are eliminated. Subsidiaries include those companies in which Imperial has both an equity interest and the continuing ability to unilaterally determine strategic, operating, investing and financing policies. Significant subsidiaries included in the consolidated financial statements include Imperial Oil Resources Limited, Imperial Oil Resources N.W.T. Limited, Imperial Oil Resources Ventures Limited and McColl-Frontenac Petroleum Inc. All of the above companies are wholly owned. A significant portion of the company s 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-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, and are recovered through surface mining methods. Currently, the company s oil sands production volumes and reserves are 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.

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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 revenues 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 were affected by this change, with the largest impact in the petroleum products segment.

Share-based compensation

The company awards share-based compensation to employees in the form of restricted stock units. Compensation expense is measured each reporting period based on the company s current stock price and is recorded as selling and general expenses in the consolidated statement of income over the requisite service period of each award. See note 9 to the consolidated financial statements for further details.

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 uncertainty in income taxes

Effective January 1, 2007, the company adopted the FASB 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 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 income tax returns. Upon the adoption of FIN 48, the company recognized a transition gain of $14 million in shareholders equity, reflected as cumulative effect of accounting change in the consolidated statement of shareholders equity. The gain reflected the recognition of several refund claims with associated interest, partly offset by increased income tax reserves. FIN 48 also resulted in a reclassification of amounts previously reported net on the balance sheet. The balance sheet reclassification resulted in a $534 million increase to long-term receivables, investments and other long-term assets; a $363 million increase to income taxes payable; a $142 million increase to other long-term obligations; and a $15 million increase to deferred tax liabilities. See note 5, Income taxes, for additional disclosures.

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 benefits 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 the 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.

millions of dollars	**Natural resources** (a) **2007**	2006	2005	**Petroleum products** **2007**	2006	2005	**Chemicals** **2007**	2006	2005
Revenues and other income									
External sales (b)	**4,539**	4,619	4,702	**19,230**	18,527	21,793	**1,300**	1,359	1,302
Intersegment sales	**4,146**	3,837	3,487	**2,305**	2,256	2,224	**335**	345	363
Investment and other income	**233**	111	331	**52**	105	60			
	8,918	8,567	8,520	**21,587**	20,888	24,077	**1,635**	1,704	1,665
Expenses									
Exploration	**106**	32	43						
Purchases of crude oil and products	**3,113**	2,841	2,837	**16,469**	16,178	19,212	**1,230**	1,209	1,191
Production and manufacturing	**2,057**	1,994	1,931	**1,232**	1,266	1,203	**185**	189	195
Selling and general (c)	**8**	13	36	**987**	1,018	1,096	**71**	76	81
Federal excise tax				**1,307**	1,274	1,278			
Depreciation and depletion	**519**	584	651	**244**	233	230	**12**	11	12
Financing costs (note 14)	**4**	2		**1**	6	2			
Total expenses	**5,807**	5,466	5,498	**20,240**	19,975	23,021	**1,498**	1,485	1,479
Income before income taxes	**3,111**	3,101	3,022	**1,347**	913	1,056	**137**	219	186
Income taxes (note 5)									
Current	**682**	602	955	**491**	174	409	**42**	60	69
Deferred	**60**	123	59	**(65)**	115	(47)	**(2)**	16	(4)
Total income tax expense	**742**	725	1,014	**426**	289	362	**40**	76	65
Net income	**2,369**	2,376	2,008	**921**	624	694	**97**	143	121
Cash flow from (used in) operating activities	**2,411**	3,024	2,440	**1,151**	507	799	**109**	161	94
Capital and exploration expenditures	**744**	787	937	**187**	361	478	**11**	13	19

Property, plant and equipment									
Cost	**15,285**	14,926	14,229	**6,655**	6,581	6,350	**718**	702	701
Accumulated depreciation and depletion	**(8,474)**	(8,255)	(7,780)	**(3,320)**	(3,178)	(3,037)	**(496)**	(484)	(474)
Net property, plant and equipment(d)(e)	**6,811**	6,671	6,449	**3,335**	3,403	3,313	**222**	218	227
Total assets	**8,171**	7,513	7,289	**6,727**	6,450	6,257	**476**	504	500

	Corporate and other			**Eliminations**			**Consolidated**		
millions of dollars	**2007**	2006	2005	**2007**	2006	2005	**2007**	2006	2005
Revenues and other income									
External sales (b)							**25,069**	24,505	27,797
Intersegment sales				**(6,786)**	(6,438)	(6,074)			
Investment and other income	**89**	67	26				**374**	283	417
	89	67	26	**(6,786)**	(6,438)	(6,074)	**25,443**	24,788	28,214
Expenses									
Exploration							**106**	32	43
Purchases of crude oil and products				**(6,786)**	(6,435)	(6,072)	**14,026**	13,793	17,168
Production and manufacturing					(3)	(2)	**3,474**	3,446	3,327
Selling and general (c)	**269**	177	364				**1,335**	1,284	1,577
Federal excise tax							**1,307**	1,274	1,278
Depreciation and depletion	**5**	3	2				**780**	831	895
Financing costs (note 14)	**31**	20	6				**36**	28	8
Total expenses	**305**	200	372	**(6,786)**	(6,438)	(6,074)	**21,064**	20,688	24,296
Income before income taxes	**(216)**	(133)	(346)				**4,379**	4,100	3,918
Income taxes (note 5)									
Current	**(52)**	(60)	(72)				**1,163**	776	1,361
Deferred	**35**	26	(51)				**28**	280	(43)

Total income tax expense	**(17)**	(34)	(123)				**1,191**	1,056	1,318
Net income	**(199)**	(99)	(223)				**3,188**	3,044	2,600
Cash flow from (used in) operating activities	**(45)**	(105)	118				**3,626**	3,587	3,451
Capital and exploration expenditures	**36**	48	41				**978**	1,209	1,475
Property, plant and equipment									
Cost	**304**	269	246				**22,962**	22,478	21,526
Accumulated depreciation and depletion	**(111)**	(104)	(103)				**(12,401)**	(12,021)	(11,394)
Net property, plant and equipment (d)(e)	**193**	165	143				**10,561**	10,457	10,132
Total assets	**1,251**	2,145	1,959	**(338)**	(471)	(423)	**16,287**	16,141	15,582

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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	**2007**	2006	2005
Total external and intersegment sales	**3,923**	3,303	3,687
Total expenses	**2,394**	1,966	1,805
Net income, after income tax	**1,224**	1,148	1,249
Total current assets	**1,211**	516	245
Long-term assets	**4,868**	4,833	4,742
Total current liabilities	**705**	810	967
Other long-term obligations	**485**	344	382
Cash flow from operating activities	**697**	1,229	1,223
Cash (used in) investing activities	**(131)**	(403)	(403)

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

millions of dollars	**2007**	2006	2005
Natural resources	**2,013**	1,936	1,633
Petroleum products	**922**	869	856
Chemicals	**768**	793	750
Total export sales	**3,703**	3,598	3,239

(c) Consolidated selling and general expenses include delivery costs from final storage areas to customers of $318 million in 2007 (2006 - $316 million, 2005 - $310 million).

(d) Includes property, plant and equipment under construction of $951 million (2006 - $782 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

millions of dollars	**2007**	2006
Long-term debt (a)(b)(c)		318
Capital leases (d)	**38**	41
Total long-term debt (e)(f)	**38**	359

(a) At 2006 year-end, the company had $818 million long-term variable-rate loans from an affiliated company of Exxon Mobil Corporation at interest equivalent to Canadian market rates. $500 million of these long-term loans was due in 2007 and included in current liabilities and $318 million was due on January 19, 2008 and included as long-term debt at 2006 year-end.

(b) In the second and third quarter of 2007, two variable-rate loans totaling $500 million matured and were replaced with two long-term variable-rate loans totaling $500 million from an affiliated company of Exxon Mobil Corporation at interest equivalent to Canadian market rates. Both loans were due in 2009. In the fourth quarter of 2007, the company retired the entire $818 million of long-term loans.

(c) The average effective rate for long-term loans was 4.5 percent for 2007.

(d) 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 10.9 percent in 2007 (2006 - 10.7 percent).

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

(f) These amounts exclude that portion of long-term debt, totaling $3 million (2006 $907 million), which matures within one year and is included in current liabilities.

5. Income taxes

millions of dollars	**2007**	2006	2005
Current income tax expense	**1,163**	776	1,361
Deferred income tax expense (a)	**28**	280	(43)
Total income tax expense (b)	**1,191**	1,056	1,318
Statutory corporate tax rate (percent)	**30.1**	32.8	35.6
Increase/(decrease) resulting from:			
Non-deductible royalty payments to governments			3.8
Resource allowance in lieu of royalty deduction			(5.2)
Enacted tax rate change	**(2.2)**	(2.7)	
Other	**(0.7)**	(4.3)	(0.6)
Effective income tax rate	**27.2**	25.8	33.6

(a) The provisions for deferred income taxes in 2007 include net (charges)/credits for the effect of changes in tax laws and rates of $90 million (2006 - $81 million, 2005 - nil).

(b) Cash outflow from income taxes, plus investment credits earned, was $1,395 million in 2007 (2006 $1,000 million,2005 $1,024 million).

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

millions of dollars	**2007**	2006	2005
Post-retirement benefits liability adjustment:			
Net actuarial loss/(gain)	**21**		
Amortization of net actuarial loss/(gain)	**(24)**		
Prior service cost	**13**		
Amortization of prior service cost	**(6)**		
Total post-retirement benefits liability adjustment	**4**	212	
Minimum pension liability adjustment		(146)	105

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	**2007**	2006
Depreciation and amortization	**1,624**	1,588
Successful drilling and land acquisitions	**276**	263
Pension and benefits	**(249)**	(311)
Site restoration	**(156)**	(161)
Net tax loss carryforwards (a)	**(37)**	(42)
Capitalized interest	**49**	50
Other	**(36)**	(42)
Deferred income tax liabilities	**1,471**	1,345
LIFO inventory valuation	**(547)**	(448)
Other	**(113)**	(125)
Deferred income tax assets	**(660)**	(573)
Valuation allowance		
Net deferred income tax liabilities	**811**	772

(a) Tax losses can be carried forward indefinitely.

Unrecognized tax benefits

The company s unrecognized income tax benefits at December 31, 2007 were $170 million. Resolution of the related tax positions will take many years to complete. Accordingly, it is difficult to predict the timing of resolution for individual tax positions. The company s effective tax rate will be reduced if any of these tax benefits is subsequently recognized.

The change in the amount of unrecognized tax benefits is as follows:

millions of dollars	**2007**

January 1 balance	142
Additions for prior years tax positions	**28**
December 31 balance	**170**

The 2007 changes in unrecognized tax benefits did not have a material effect on the company s net income or cash flow. The company s tax filings from 2003 to 2006 are subject to examination by the tax authorities. The Canada Revenue Agency has proposed certain adjustments to the company s filings for several years in the period 1987 to 2002. Management is currently evaluating those proposed adjustments. Management believes that a number of outstanding matters before 2003 is expected to be resolved in 2008. The impact on unrecognized tax benefits and the company s effective income tax rate from these matters is not expected to be material.

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

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.

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Notes to consolidated financial statements (continued)

	Pension Benefits		Other post-retirement benefits	
	2007	2006	**2007**	2006
Assumptions used to determine benefit obligations at December 31 (percent)				
Discount rate	**5.75**	5.25	**5.75**	5.25
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	**4,716**	4,784	**441**	458
Current service cost	**100**	100	**6**	8
Interest cost	**246**	238	**23**	23
Amendments	**41**			(2)
Actuarial loss/(gain)	**(131)**	(122)	**(25)**	(19)
Benefits paid (a)	**(287)**	(284)	**(19)**	(27)
Projected benefit obligation at December 31	**4,685**	4,716	**426**	441
Accumulated benefit obligation at December 31	**4,208**	4,207		
Change in plan assets				
Fair value at January 1	**4,089**	3,419		
Actual return on plan assets	**93**	514		
Company contributions	**163**	395		
Benefits paid (b)	**(247)**	(239)		
Fair value at December 31	**4,098**	4,089		
Plan assets in excess of/(less than) projected benefit obligation at December 31				
Funded plans	**(213)**	(294)		
Unfunded plans	**(374)**	(333)	**(426)**	(441)

Total (c)	**(587)**	(627)	**(426)**	(441)

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

	Pension Benefits			Other post-retirement benefits		
millions of dollars	**2007**	2006	2005	**2007**	2006	2005
Amounts recorded in the consolidated balance sheet consist of:						
Current liabilities	**(34)**	(28)		**(25)**	(23)	
Other long-term obligations	**(553)**	(599)		**(401)**	(418)	
Total recorded	**(587)**	(627)		**(426)**	(441)	
Amounts recorded in accumulated other comprehensive income consist of:						
Net actuarial loss/(gain)	**977**	947		**42**	73	
Prior service cost	**95**	74				
Total recorded in accumulated other comprehensive income, before tax	**1,072**	1,021		**42**	73	
Assumptions used to determine net periodic benefit benefit cost for years ended December 31 (percent)						
Discount rate	**5.25**	5.00	5.75	**5.25**	5.00	5.75
Long-term rate of compensation increase	**3.50**	3.50	3.50	**3.50**	3.50	3.50
Long-term rate of return on funded assets	**8.00**	8.25	8.25			

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millions of dollars	Pension Benefits 2007	2006	2005	Other post-retirement benefits 2007	2006	2005
Components of net periodic benefit cost						
Current service cost	**100**	100	86	**6**	8	7
Interest cost	**246**	238	239	**23**	23	24
Expected return on plan assets	**(329)**	(299)	(257)			
Amortization of prior service cost	**20**	20	25			
Recognized actuarial loss/(gain)	**76**	114	83	**6**	8	7
Net periodic benefit cost	**113**	173	176	**35**	39	38
Changes in amounts recorded in accumulated other comprehensive income						
Net actuarial loss/(gain)	**105**	72	317	**(25)**	73	
Amortization of net actuarial loss/(gain) included in net periodic benefit cost	**(76)**			**(6)**		
Prior service cost	**41**	74				
Amortization of prior service cost included in net periodic benefit cost	**(20)**					
Total recorded in accumulated other comprehensive income	**50**	146	317	**(31)**	73	
Total recorded in net periodic benefit cost and other accumulated other comprehensive income, before tax	**163**	319	493	4	112	38

Costs for defined contribution plans, primarily the employee savings plan, were $31 million in 2007 (2006 $30 million, 2005 $30 million).

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

millions of dollars	Total pension and other post-retirement benefits 2007	2006	2005
(Charge)/credit to accumulated other comprehensive income, before tax	**(19)**	(219)	(317)
Deferred income tax (charge)/credit (note 5)	**4**	66	105
(Charge)/credit to accumulated other comprehensive income, after tax	**(15)**	(153)	(212)

The preceding data in this note conforms 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 2008 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 2007 long-term expected return of 8.00 percent used in the calculations of pension expense compares to an actual rate of return over the past decade of 8.29 percent.

The company s pension plan asset allocation at December 31, 2006 and 2007, and target allocation for 2008 are as follows:

	Target allocation	Percentage of plan assets at December 31	
Asset category (percent)	2008	**2007**	2006
Equity securities	50 75	**61**	64
Debt securities	25 50	**38**	36
Other	0 10	**1**	

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

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Notes to consolidated financial statements (continued)

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	**2007**	2006
For funded pension plans with accumulated benefit obligations in excess of plan assets:		
Projected benefit obligation	**398**	375
Accumulated benefit obligation	**318**	308
Fair value of plan assets	**254**	239
Accumulated benefit obligation less fair value of plan assets	**64**	69
For unfunded plans covered by book reserves:		
Projected benefit obligation	**373**	333
Accumulated benefit obligation	**347**	314

Estimated 2008 amortization from accumulated other comprehensive income millions of dollars	Pension benefits	Other post-retirement benefits
Net actuarial loss/(gain) (a)	81	4
Prior service cost (b)	18	

(a) The company amortizes the net balance of actuarial loss/(gain) over the average remaining service period of active plan participants.

(b) The company amortizes prior service cost on a straight-line basis as permitted under SFAS 87 and SFAS 106.

Cash flows

Benefit payments expected in:

millions of dollars	Pension benefits	Other post-retirement benefits
2008	261	24
2009	265	24
2010	268	24
2011	273	24
2012	279	25
2013 - 2017	1,505	126

In 2008, the company expects to make cash contributions of about $170 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) millions of dollars	One percent increase	One percent decrease
Rate of return on plan assets:		
Effect on net benefit cost, before tax	(40)	40
Discount rate:		
Effect on net benefit cost, before tax	(60)	70
Effect on benefit obligation	(555)	680
Rate of pay increases:		
Effect on net benefit cost, before tax	45	(35)
Effect on benefit obligation	160	(140)

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	44	(35)

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7. Other long-term obligations

millions of dollars	**2007**	2006
Employee retirement benefits (note 6)(a)	**954**	1,017
Asset retirement obligations and other environmental liabilities (b)	**522**	438
Share-based incentive compensation liabilities (note 9)	**210**	128
Other obligations	**228**	100
Total other long-term obligations	**1,914**	1,683

(a) Total recorded employee retirement benefit obligations also include $59 million in current liabilities (2006 $51 million).
(b) Total asset retirement obligations and other environmental liabilities also include $74 million in current liabilities (2006 $97 million).

The following table summarizes the activity in the liability for asset retirement obligations:

millions of dollars	**2007**	2006
January 1 balance	422	367
Additions	**71**	61
Accretion	**25**	22
Settlement	**(30)**	(28)
December 31 balance	**488**	422

8. Derivatives and financial instruments

The company did not enter into any energy derivatives, foreign-exchange forward contracts or currency and interest-rate swaps in the past three years. The company maintains a system of controls that includes a policy covering the authorization, reporting and monitoring of derivative activity.

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

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

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

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

Under the restricted stock unit plan, each unit entitles the recipient to the conditional right to receive from the company, upon exercise, an amount equal to the five-day average of the closing price of the company s common shares on the Toronto Stock Exchange on and immediately prior to the exercise dates. Fifty percent of the units are exercised three years following the grant date, and the remainder are exercised seven years following the grant date. For units granted in 2002 to 2005, the exercise date has been changed from December 31 to December 4 for units exercised in 2006 and subsequent years. For units granted in 2002, 2003, 2004 and 2005 to be exercised subsequent to the company s May 2006 three-for-one share split, the company has indicated that it will increase the cash payment or number of shares issued per unit, as the case may be, by a factor of three.

All units require settlement by cash payments with 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 the Financial Accounting Standards Board s (FASB) revised statement of Financial Accounting Standards No.123 (SFAS 123R), Share-based Payment , the company accounts for these units by using the fair-value-based method. The fair value of awards in the form of incentive share, deferred share and restricted stock units is the market price of the company s stock. Under this method, compensation expense related to the units of these programs is measured each reporting period based on the company s current stock price and is recorded in

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Notes to consolidated financial statements (continued)

the consolidated statement of income over the requisite service period of each award. All incentive share units have vested as of December 31, 2004.

The following table summarizes information about these units for the year ended December 31, 2007:

	Incentive share units	Deferred share units	Restricted stock units
Outstanding at January 1, 2007	9,071,250	84,448	9,996,390
Granted		**6,078**	**1,713,488**
Exercised	**(2,316,300)**		**(1,471,847)**
Cancelled or adjusted	**3,900**		**(18,180)**
Outstanding at December 31, 2007	**6,758,850**	**90,526**	**10,219,851**

The compensation expense charged against income for these programs was $202 million, $133 million, and $238 million for the year ended December 31, 2007, 2006, and 2005, respectively. Total income tax benefit recognized in income related to this compensation expense was $67 million, $45 million and $127 million for the year ended December 31, 2007, 2006 and 2005, respectively. Cash payments of $159 million, $162 million and $169 million for these programs were made in 2007, 2006 and 2005, respectively.

As of December 31, 2007, there was $294 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, 2007.

Incentive stock options

In April 2002, incentive stock options were granted for the purchase of the company s common shares. For units exercised subsequent to the company s May 2006 three-for-one split, the company has indicated that it will give the option holders the right to purchase three shares for each original stock option granted. The exercise price is $15.50 per share (adjusted to reflect the three-for-one share split). 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 the year ended December 31, 2007, 2006 and 2005. Cash received from stock option exercises for the year ended December 31, 2007 was $12 million. The aggregate intrinsic value of stock options exercised was $25 million, $18 million and $43 million in the year ended December 31, 2007, 2006 and 2005, respectively, and for the balance of outstanding stock options is $185 million as at December 31, 2007.

The average fair value of each option granted during 2002 was $4.23 (adjusted to reflect the three-for-one share split). The fair value was estimated at the grant date using an option-pricing model with the following weighted average assumptions: risk-free interest rate of 5.7 percent, expected life of five years, volatility of 25 percent and a dividend yield of 1.9 percent.

The company has purchased shares on the market to fully offset the dilutive effects from the exercise of stock options. Purchase may be discontinued at any time without prior notice.

The following table summarizes information about stock options for the year ended December 31, 2007:

		2007	
	Units	Exercise price	Remaining contractual term
		(dollars)	(years)
Incentive stock options			
Outstanding at January 1, 2007	5,527,665	15.50	
Granted			
Exercised	**(791,385)**	**15.50**	
Cancelled or adjusted	**(7,500)**		
Outstanding at December 31, 2007	**4,728,780**	**15.50**	**4.3**

10. Investment and other income

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

millions of dollars	**2007**	2006	2005
Proceeds from asset sales	**279**	212	440
Book value of assets sold	**64**	78	96
Gain/(loss) on asset sales, before tax (a)(b)	**215**	134	344
Gain/(loss) on asset sales, after tax (a)(b)	**156**	96	233

(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.

(b) 2007 included a gain of $200 million ($142 million, after tax) from the sale of the company s interests in a natural gas producing property in British Columbia and in the Willesden Green producing property.

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11. Litigation and other contingencies

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

In 2007, the Alberta government proposed changes to the oil and gas and generic oil sands royalty regime beginning in 2009. The company believes that this proposal could have an adverse effect on future company investments in Alberta and the company s future financial results. The magnitude of the potential impact will depend on the final form of enacted legislation and the future prices of oil and gas and cannot be reasonably estimated at this time. The Syncrude Joint Venture owners have a Crown Agreement with the Province of Alberta that codifies the royalty rates through December 31, 2015. The Syncrude Joint Venture owners are in discussions with the Alberta government to determine if an amended agreement can be negotiated that would transition Syncrude to the new generic oil sands royalty regime before 2016.

The company was contingently liable at December 31, 2007 for a maximum of $83 million relating to guarantees for purchasing operating equipment and other assets from its rural marketing associates upon expiry of the associate agreement or the resignation of the associate. The company expects that the fair value of the operating equipment and other assets so purchased would cover the maximum potential amount of future payment under the guarantees.

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

	Payments due by period						
millions of dollars	2008	2009	2010	2011	2012	After 2012	Total
Unconditional purchase obligations(a)	**99**	**96**	**64**	**64**	**121**	**38**	**482**

(a) Undiscounted obligations of $482 million mainly pertain to pipeline throughput agreements. Total payments under unconditional purchase obligations were $94 million (2006 - $100 million,2005 - $104 million). The present value of these commitments, excluding imputed interest of $84 million, totaled $398 million.

12. Common shares

thousands of shares	**As at Dec. 31 2007**	As at Dec. 31 2006
Authorized	**1,100,000**	1,100,000

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 2006, the company purchased shares under twelve 12-month normal course share purchase programs, as well as an auction tender. On June 25, 2007, another 12-month normal course share purchase program was implemented with an allowable purchase of 46.5 million shares (five percent of the total at June 22, 2007), 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 2005	750,109	8,635
2006	45,514	1,818
2007	**50,516**	**2,358**
Cumulative purchases to date	846,139	12,811

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, 2005	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
Issued for cash under the stock option plan	**791**	**12**
Purchases	**(50,516)**	**(89)**
Balance as at December 31, 2007	**903,263**	**1,600**

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Notes to consolidated financial statements (continued)

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

	2007	2006	2005
Net income per common share - basic			
Net income (millions of dollars)	**3,188**	3,044	2,600
Weighted average number of common shares outstanding (thousands of shares)	**928,527**	975,128	1,024,119
Net income per common share (dollars)	**3.43**	3.12	2.54
Net income per common share - diluted			
Net income (millions of dollars)	**3,188**	3,044	2,600
Weighted average number of common shares outstanding (thousands of shares)	**928,527**	975,128	1,024,119
Effect of employee stock-based awards (thousands of shares)	**5,811**	4,460	4,179
Weighted average number of common shares outstanding, assuming dilution (thousands of shares)	**934,338**	979,588	1,028,298
Net income per common share (dollars)	**3.41**	3.11	2.53

13. Miscellaneous financial information

In 2007, net income included an after-tax gain of $25 million (2006 $14 million gain, 2005 $5 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, 2007 by $1,953 million (2006 $1,509 million). Inventories of crude oil and products at year-end consisted of the following:

million of dollars	**2007**	2006
Crude oil	**211**	211
Petroleum products	**298**	277
Chemical products	**43**	54
Natural gas and other	**14**	14
Total inventories of crude oil and products	**566**	556

Research and development costs in 2007 were $89 million (2006 $73 million, 2005 $68 million) before investment tax credits earned on these expenditures of $6 million (2006 $7 million, 2005 $10 million). Research and development costs are included in expenses due to the uncertainty of future benefits.

Cash flow from operating activities included dividends of $22 million received from equity investments in 2007 (2006 $18 million, 2005 $21 million).

14. Financing costs

millions of dollars	**2007**	2006	2005
Debt-related interest	**62**	63	45
Capitalized interest	**(36)**	(48)	(41)
Net interest expense	**26**	15	4
Other interest	**10**	13	4
Total financing costs (a)	**36**	28	8

(a) Cash interest payments in 2007 were $80 million (2006 - $71 million, 2005 - $45 million). The weighted average interest rate on short-term borrowings in 2007 was 5.1 percent (2006 4.1 percent).

15. Leased facilities

At December 31, 2007, the company held non-cancelable operating leases covering office buildings, rail cars, service stations and other properties with minimum undiscounted lease commitments totaling $232 million as indicated in the following table:

	Payments due by period						
millions of dollars	2008	2009	2010	2011	2012	After 2012	Total
Lease payments under minimum commitments (a)	**55**	**52**	**45**	**26**	**15**	**39**	**232**

(a) Total rental expense incurred for operating leases in 2007 was $79 million (2006 - $79 million, 2005 - $83 million) which included minimum rental expenditures of $67 million (2006 - $66 million, 2005 - $63 million). Related rental income was not material.

16. Transactions with related parties

Revenues and expenses of the company also include the results of transactions with Exxon Mobil Corporation and affiliated companies (ExxonMobil) in the normal course of operations. These were conducted on terms as favourable as they would have been with unrelated parties and primarily consisted of the purchase and sale of crude oil, natural gas, petroleum and chemical products, as well as transportation, technical and engineering services. Transactions with ExxonMobil also included amounts paid and received in connection with the company s participation in a number of 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

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provide organizational efficiencies and to reduce costs. No separate legal entities were created from this arrangement. Separate books of account continue to be maintained for the company and ExxonMobil. The company and ExxonMobil retain ownership of their respective assets and there is no impact on operations or reserves. During 2007, the company entered into agreements with Exxon Mobil Corporation and one of its affiliated companies that provide for the delivery of management, business and technical services to Syncrude Canada Ltd. by ExxonMobil.

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

As at December 31, 2007, the company had outstanding loans of $33 million (2006 - $33 million) to Montreal Pipe Line Limited, in which the company has an equity interest, for financing of the equity company s capital expenditure programs and working capital requirements.

17. Net payments/payables to governments

millions of dollars	**2007**	2006	2005
Current income tax expense (note 5)	**1,163**	776	1,361
Federal excise tax	**1,307**	1,274	1,278
Property taxes included in expenses	**112**	100	99
Payroll and other taxes included in expenses	**56**	46	52
GST/QST/HST collected (a)	**2,573**	2,715	2,703
GST/QST/HST input tax credits (a)	**(2,095)**	(2,293)	(2,344)
Other consumer taxes collected for governments	**1,707**	1,667	1,613
Crown royalties	**1,016**	904	620
Total paid or payable to governments	**5,839**	5,189	5,382
Less investment tax credits and other receipts	**9**	11	9
Net paid or payable to governments	**5,830**	5,178	5,373
Net paid or payable to:			
Federal government	**2,682**	2,352	2,736
Provincial governments	**3,036**	2,726	2,538
Local governments	**112**	100	99
Net paid or payable to governments	**5,830**	5,178	5,373

(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.

18. Additional SFAS 158 adoption disclosure

In its 2006 financial statements, the company reported the adjustment related to the adoption of SFAS 158. Based on further regulatory guidance, this adjustment should have been reported as an adjustment to ending 2006 accumulated other comprehensive income. The amount reported by the company as 2006 comprehensive income (nonowner changes in equity) was $2,891 million. Excluding the negative $487 million SFAS 158 adoption adjustment (which was separately disclosed in note 6 to the 2006 consolidated financial statements, Employee retirement benefits), the amount would have been $3,378 million. The company has accordingly revised the presentation of 2006 comprehensive income (nonowner changes in equity) in its 2007 financial statements.