IMPERIAL OIL LTD
Form 10-K
February 28, 2007

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

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

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

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

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

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

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

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

(Title of Class)

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

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

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

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

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12 b-2 of the Securities Exchange Act of 1934).
Yes o No þ

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

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

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

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

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

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

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

PART I

Item 1. Business.

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

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

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

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

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

(1) Export sales are reported in note 3 to the consolidated financial statements on page F-9. Total external sales include $4,894 million for 2005, $3,584 million for 2004, $2,851 million for 2003 and $2,431 million for 2002 for purchases/sales contracts with the same counterparty. Associated costs were included in purchases of crude oil and products . Effective January 1, 2006, these purchases/sales were recorded on a net basis. See note 1, Summary of significant Accounting Policies.

(2) These amounts are presented as if each segment

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

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

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

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

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

Natural Resources

Petroleum and Natural Gas Production

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Conventional Oil and Gas

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

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

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

Cold Lake

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

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

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

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

The Province of Alberta, in its capacity as lessor of the Cold Lake heavy oil leases, is entitled to a royalty on production from the Cold Lake production project. The royalty agreement which applied through the end of 1999, provided for a royalty calculated at the greater of five percent of gross revenue or 30 percent of an amount based on revenue net of operating and capital costs. It also provided for a royalty waiver on equity natural gas produced in Alberta and deemed to be consumed in generating steam at the company s Cold Lake operations. In late 2000, the company entered into an agreement with the Province of Alberta, effective January 1, 2000, on a transitional royalty arrangement that will apply to all of the company s current and proposed operations at Cold Lake until the end of 2007, at which time the generic Alberta regulations for heavy oil royalties will apply. The post-transition royalty regulation, which will become effective in 2008, provides for a royalty calculated at the greater of one percent of gross revenue or 25 percent of an amount based on revenue net of operating and capital costs, but with no gas royalty waiver. The transition agreement, which is effective between 2000 and 2007 inclusive, makes provision for the differences between the two royalty regimes (higher bitumen royalties with gas royalty waiver vs. lower bitumen royalties and no gas royalty waiver). This transition will bring all phases of the company s Cold Lake operations under one royalty agreement with common terms and conditions. The transition is not expected to materially change the amount of royalties that the company would have otherwise paid under the pre-existing royalty arrangements. The effective royalty on gross production was 17 percent in 2006, 11 percent in 2005 and 2004, 10 percent in 2003 and five percent in 2002.

Other Heavy Oil Activity

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

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

Syncrude Mining Operations

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

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

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

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

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

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

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

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

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

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

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