IMPERIAL OIL LTD
Form 10-K
February 28, 2008

Table of Contents

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

Table of Contents

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.

Table of Contents

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.

4

Table of Contents

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.

Table of Contents

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 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.

Table of Contents

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**			