IMPERIAL OIL LTD
Form 10-K
February 27, 2012
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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, 2011

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 whether the registrant has submitted electronically and posted on its corporate web site, if any, every interactive data file required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yesü 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 the definitions 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 2011 second fiscal quarter, the aggregate market value of the voting stock held by non-affiliates of the registrant was Canadian $11,574,568,203 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, 2012, was 847,670,521.

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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 United States (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.

dollars	**2011**	2010	2009	2008	2007
Rate at end of period	**0.9835**	0.9991	0.9559	0.8170	1.0120
Average rate during period	**1.0144**	0.9659	0.8793	0.9335	0.9376
High	**1.0584**	1.0040	0.9719	1.0291	1.0908
Low	**0.9430**	0.9280	0.7695	0.7710	0.8437

On February 15, 2012, 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 $1.0035 U.S. = $1.00 Canadian.

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Forward-looking statements

Statements in this report regarding expectations, plans and future events or conditions are forward-looking statements. Actual future results, including demand growth and energy source mix; production growth and mix; project start-ups; the effect of changes in prices and other market conditions; financing sources; and capital and environmental expenditures could differ materially depending on a number of factors, such as changes in the supply of and demand for crude oil, natural gas, and petroleum and petrochemical products; political or regulatory events; project schedules; commercial negotiations; and other factors discussed in Item 1A of this annual report on Form 10-K and in the management s discussion and analysis of financial condition and results of operations contained in Item 7.

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. 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 a major producer of crude oil and natural gas and the largest petroleum refiner and a leading marketer of petroleum products. It is also a major producer of petrochemicals.

The company s operations are conducted in three main segments: Upstream, Downstream and Chemical. Upstream operations include the exploration for, and production of, conventional crude oil, natural gas, synthetic oil and bitumen. Downstream operations consist of the transportation and refining of crude oil, blending of refined products, and the distribution and marketing of those products. Chemical operations consist of the manufacturing and marketing of various petrochemicals.

Financial information about segments for the company are contained in the Financial section of this report under Note 2 to the consolidated financial statements: Business segments .

Upstream

Disclosure of Reserves

Summary of oil and gas reserves at year-end

The table below summarizes the net proved reserves for the company, as at December 31, 2011, as detailed in the Oil and gas reserves part of the Financial section, starting on page 79 of this report.

All of the company s reported reserves are located in Canada. The company has reported proved reserves based on the average of the first-day-of-the-month price for each month during the last 12-month period ending December 31. Natural gas is converted to an oil-equivalent basis at six million cubic feet per one thousand barrels. No major discovery or other favorable or adverse event has occurred since December 31, 2011 that would cause a significant change in the estimated proved reserves as of that date, except for the following. In February 2012, the Nabiye expansion project at Cold Lake was approved by the company s board. Proved reserves from the Nabiye project will be included in 2012 year-end reporting for the first time.

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	Liquids (a) millions of barrels	Natural gas billions of cubic feet	Synthetic oil millions of barrels	Bitumen millions of barrels	Total oil-equivalent basis millions of barrels
Net proved reserves:					
Developed	**55**	**360**	**653**	**519**	**1,287**
Undeveloped		**62**		**1,894**	**1,904**
Total net proved	**55**	**422**	**653**	**2,413**	**3,191**

(a) Liquids include crude oil, condensate and natural gas liquids (NGLs). NGL proved reserves are not material and are therefore included under liquids.

The estimation of proved reserves, which is based on the requirement of reasonable certainty, is an ongoing process based on rigorous technical evaluations, commercial and market assessments and detailed analysis of well information such as flow rates and reservoir pressure declines. Furthermore, the company only records proved reserves for projects which have received significant funding commitments by management made toward the development of the reserves. 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 projections of long-term oil and gas price levels.

Technologies used in establishing proved reserves estimates

Additions to Imperial s proved reserves in 2011 were based on estimates generated through the integration of available and appropriate data, utilizing well established technologies that have been demonstrated in the field to yield repeatable and consistent results.

Data used in these integrated assessments included information obtained directly from the subsurface via wellbores, such as well logs, reservoir core samples, fluid samples, static and dynamic pressure information, production test data, and surveillance and performance information. The data utilized also included subsurface information obtained through indirect measurements, including high-quality 2-D and 3-D seismic data, calibrated with available well control information. Where applicable, surface geological information was also utilized. The tools used to interpret the data included proprietary seismic processing software, proprietary reservoir modeling and simulation software and commercially available data analysis packages.

In some circumstances, where appropriate analog reservoirs were available, reservoir parameters from these analogs were used to increase the quality of and confidence in the reserves estimates.

Preparation of reserves estimates

Imperial has a dedicated reserves management group that is separate from the base operating organization. Primary responsibilities of this group include oversight of the reserves estimation process for compliance with Securities and Exchange Commission (SEC) rules and regulations, review of annual changes in reserves estimates, and the reporting of Imperial s proved reserves. In addition, this group provides training to personnel involved in the reserve estimation and reporting processes within Imperial.

Key components of the reserves estimation process include technical evaluations and analysis of well and field performance and a rigorous peer review. The reserves management group maintains a central computerized database containing the official company reserves estimates and production data. Appropriate controls, including limitations on database access and update capabilities, are in place to ensure data integrity within this central computerized database. An annual review of the system s controls is performed by internal audit. No changes may be made to reserves estimates in the central database, including the addition of any new initial reserves estimates or subsequent revisions, unless those changes have been thoroughly reviewed and evaluated by duly authorized personnel within the base operating organization. In addition, changes to reserves estimates that exceed certain thresholds will require further review and approval of the appropriate level of management within the operating organization, culminating in reviews with and approval by senior management and the company s board of directors.

The Operations Technical Subsurface Engineering Manager, who is an employee of the company, has evaluated the company s reserves data and filed a report to the Canadian securities regulatory authorities. The company s internal reserves evaluation staff consists of about 59 persons with an average of approximately 15 years of relevant experience in evaluating reserves, of whom about 37 persons are qualified reserves evaluators for purposes of Canadian securities regulatory requirements. The company s internal reserves evaluation management team is made up of about 12 persons with an average of approximately 12 years of relevant experience in evaluating and managing the evaluation of reserves. No independent qualified reserves evaluator or auditor was involved in the preparation of the company s reserves data.

Proved undeveloped reserves

As of December 31, 2011, approximately 60 percent of the company s proved reserves were proved undeveloped reserves reflecting volumes of 1,904 million oil-equivalent barrels. Nearly all of those undeveloped reserves are associated with either the Kearl project or Cold Lake field. This compared to approximately 47 percent or 1,209 million oil-equivalent barrels of proved undeveloped reserves reported at the end of 2010. In December 2011, Kearl expansion was approved by the company s board. Increased proved undeveloped reserves in 2011 were primarily due to the initial booking of the approved Kearl expansion.

One of the company s requirements to report resources as proved reserves is that management has made significant funding commitments towards the development of the reserves. The company has a disciplined investment strategy and many major fields require a significant lead-time in order to be developed. The company made investments of about $3.1 billion during the year to progress the development of reported proved undeveloped reserves. The largest project under development in 2011 was the initial development of Kearl which was 87 percent complete at 2011 year-end and is expected to start-up in late 2012. Proved undeveloped reserves at Cold Lake are associated with the ongoing drilling program. In 2011, Imperial moved 68 million barrels from proved undeveloped to proved developed reserves at Cold Lake.

Oil and gas production, production prices and production costs

Average daily production of oil

The company s average daily oil production by final products sold during the three years ended December 31, 2011 was as follows. All reported production volumes were from Canada.

thousands of barrels a day		**2011**	2010	2009
Liquids:	- gross (a)	**23**	30	33
	- net (b)	**17**	22	26
Bitumen (c):	- gross (a)	**160**	144	141
	- net (b)	**120**	115	120
Synthetic oil (d):	- gross (a)	**72**	73	70
	- net (b)	**67**	67	65
Total:	- gross (a)	**255**	247	244
	- net (b)	**204**	204	211

(a) Gross production is the company s share of production (excluding purchases) before deduction of the mineral owners or governments share or both.
(b) Net production is gross production less the mineral owners or governments share or both.
(c) All of the company s bitumen production volumes were from the Cold Lake production operation.
(d) All of the company s synthetic oil production volumes were from the company s share of production volumes in the Syncrude joint venture.

In 2011, third party pipeline unplanned downtime, which resulted in reduced production at the Norman Wells field, and natural reservoir decline were the main contributors to lower conventional liquids production. Higher gross bitumen volumes were due to contributions from new wells steamed in 2010 and 2011, increased recoveries as a result of technology applications and the cyclic nature of production at Cold Lake. Synthetic oil production at Syncrude was in line with 2010.

In 2010, planned maintenance activities at the Norman Wells field and natural reservoir decline were the main contributors to the lower liquids production. Higher gross bitumen volumes in 2010 were due to improved facility reliability as well as the cyclic nature of production at Cold Lake. Net bitumen production at Cold Lake was lower due to higher royalties. Synthetic oil production at Syncrude was higher primarily due to improved operational reliability.

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Average daily production and sales of natural gas

The company s average daily production and sales of natural gas during the three years ended December 31, 2011 are set forth below. All reported production volumes were from Canada. All gas volumes in this report are calculated at a pressure base of 14.73 pounds per square inch absolute at 60 degrees Fahrenheit.

millions of cubic feet a day	**2011**	2010	2009
Gross production (a) (b)	**254**	280	295
Net production (c)	**228**	254	274
Sales (d)	**237**	264	272

(a) Gross production is the company s share of production (excluding purchases) before deduction of the mineral owners or governments share or both.
(b) Production of natural gas includes amounts used for internal consumption with the exception of the amounts reinjected.
(c) Net production is gross production less the mineral owners or governments share or both.
(d) 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.

In 2011, lower gross gas production volume was primarily a result of natural reservoir decline.

In 2011, the company sold its interests in shallow gas properties in the Medicine Hat, Alberta area, Coleville-Hoosier natural gas producing property in Saskatchewan and the Rainbow Lake producing property in Alberta, realizing a gain of about $76 million. Production for the company s share of the properties averaged about 56 million cubic feet of natural gas a day and one thousand barrels of crude oil a day in 2010.

In 2010, lower gross gas production volume was primarily a result of natural reservoir decline and maintenance activities.

Total average daily oil-equivalent basis production

The company s total average daily production expressed in oil-equivalent basis is set forth below, with natural gas converted to an oil-equivalent basis at six million cubic feet per one thousand barrels.

thousands of barrels a day	**2011**	2010	2009
Total production oil-equivalent basis:			
- gross (a)	**297**	294	293
- net (b)	**242**	246	257

(a) Gross production is the company s share of production (excluding purchases) before deduction of the mineral owners or governments share or both.
(b) Net production is gross production less the mineral owners or governments share or both.

Average unit sales price

The company s average unit sales price and average unit production costs by product type for the three years ended December 31, 2011, were as follows:

dollars a barrel	**2011**	2010	2009
Liquids	**77.34**	65.84	53.91
Synthetic oil	**101.43**	80.63	69.69
Bitumen	**63.95**	58.36	51.81
dollars per thousand cubic feet			
Natural gas	**3.59**	4.04	4.11

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Average unit production costs

dollars a barrel	**2011**	2010	2009
Synthetic oil	**48.33**	45.17	43.95
Bitumen	**19.30**	18.43	17.17
Total oil-equivalent basis (a)	**26.63**	24.76	23.66

(a) Includes liquids, bitumen, synthetic oil and natural gas.

Canadian crude oil prices are mainly determined by international crude oil markets and the impact of foreign exchange rates.

Canadian natural gas prices are determined by North American gas markets and the impact of foreign exchange rates.

In 2011, unit production costs increased on a net basis primarily due to lower net volumes as a result of higher royalty costs, increased maintenance costs at Syncrude and pre-startup costs associated with the Kearl initial development project.

In 2010, unit production costs increased on a net basis primarily due to lower net volumes as a result of higher royalty costs.

Drilling and other exploratory and development activities

The company has been involved in the exploration for and development of petroleum and natural gas in Canada only.

Wells Drilled

The following table sets forth the conventional and bitumen net exploratory and development wells that were drilled or participated in by the company during the three years ending December 31, 2011.

wells	**2011**	2010	2009
Net productive exploratory:			
Oil and gas	**3**	6	2
Bitumen			
Net dry exploratory:			
Oil and gas			
Bitumen			
Net productive development:			
Oil and gas	**62**	73	218
Bitumen	**34**	110	60
Net dry development:			
Oil and gas			
Bitumen			
Total	**99**	189	280

In 2011, the following wells were drilled to add productive capacity: 34 bitumen development wells in undeveloped areas of existing phases at Cold Lake; 60 gas development wells in the shallow gas area and two net tight oil wells in the company s existing conventional acreage.

Two net exploratory gas wells were drilled in the Horn River shale gas play, as part of the company s ongoing evaluation of its holdings in the area, and one net exploratory tight oil well was drilled to evaluate some of the company s holdings in Alberta.

In 2010, 110 bitumen development wells were drilled to add new productive capacity from undeveloped areas of existing phases at Cold Lake. In addition, 71 gas development wells were drilled in 2010 adding productivity primarily in the shallow gas area. Additionally, one oil development well was drilled in Norman Wells and one oil development well was drilled in the Pembina area.

Also in 2010, six net exploratory gas wells were drilled in the Horn River shale gas play, as part of the company s ongoing evaluation of its holdings in the area.

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In 2009, 60 bitumen development wells were drilled to add new productive capacity from undeveloped areas of existing phases at Cold Lake. In addition, 216 gas development wells were drilled in 2009 adding productivity primarily in the shallow gas area. Additionally, two oil development wells were drilled in Norman Wells. Also in 2009, two net exploratory gas wells were drilled in the Horn River shale gas play as part of the company s ongoing evaluation of its holdings in the area.

Wells drilling

At December 31, 2011, the company was participating in the drilling of the following exploratory and development wells. All wells were located in Canada.

	2011	
wells	Gross	Net
Oil and gas	**12**	**6**
Bitumen	**28**	**28**
Total	**40**	**34**

Exploratory and development activities regarding oil and gas resources

Cold Lake

To maintain production at Cold Lake, capital expenditures for additional production wells and associated facilities are required periodically. In 2011, the company executed a development drilling program of 34 wells on existing phases.

In 2012, a development drilling program is planned within the approved development area to add productive capacity from undeveloped areas of existing Cold Lake phases. In February 2012, the Nabiye expansion project at Cold Lake was approved by the company s board and appropriated for $2 billion. The expansion is expected to bring on additional production of more than 40,000 barrels a day, before royalties, at Cold Lake. Start-up is expected to be year-end 2014.

The company also conducts experimental pilot operations to improve recovery of bitumen from wells by means of new drilling, production and recovery techniques.

Western provinces

In 2011, drilling and facility construction were underway on the production pilot of an eight horizontal-well pad (four net wells) in the Horn River shale gas acreage to evaluate well productivity and cost performance. The pilot production is scheduled to start-up in late 2012.

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 JRP report was released in late 2009. In late 2010, the NEB announced its approval of plans to build and operate the project and 264 conditions in areas such as engineering, safety and environmental protection. Federal cabinet approved the project in early 2011.

Beaufort Sea

In 2007, the company acquired a 50 percent interest in an exploration licence in the Beaufort Sea. As part of the evaluation, a 3-D seismic survey was conducted in 2008. In 2009, 2010 and 2011, the company carried out data collection programs to support environmental studies and safe exploration drilling operations.

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In 2010, the company executed an agreement to cross-convey interests with another company to acquire a 25 percent interest in an additional Beaufort Sea exploration licence. As a result of that agreement, the company s interest in its original licence was reduced to 25 percent.

Atlantic offshore

The company holds a 15 percent interest in deepwater exploration blocks in the Orphan Basin, located off the east coast of Newfoundland. In 2004 and 2005, the company participated in 3-D seismic surveys in this area. Exploration wells were drilled in 2007 and 2010. In 2009, the company participated in a remote reservoir resistivity survey of the area.

Other oil sands activity

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

Exploratory and development activities regarding oil and gas resources extracted by mining methods

Kearl project

The company holds a 70.96 percent participating interest in the Kearl oil sands project, a joint venture with ExxonMobil Canada Properties, a subsidiary of Exxon Mobil Corporation. The Kearl project will recover shallow deposits of oil sands using open-pit mining methods. The project is located approximately 40 miles north of Fort McMurray, Alberta.

The Kearl project received approvals from the Province of Alberta in 2007 and the Government of Canada in 2008. The Province of Alberta issued an operating and construction licence in 2008, which permits the project to mine oil sands and produce bitumen from approved development areas on oil sands leases.

Production from the initial development is expected to be at an initial rate of approximately 110,000 barrels of bitumen a day, before royalties, of which the company s share would be about 78,000 barrels a day. In 2011, the initial development was reconfigured with a capital appropriation of $10.9 billion, of which the company s share would be $7.7 billion. At the end of 2011, initial development was 87 percent complete, with expected start-up in late 2012.

In 2011, the expansion was approved by the company s board and appropriated for $8.9 billion, of which the company s share is $6.3 billion. It is expected to bring on additional production of 110,000 barrels of bitumen a day, before royalties, by late 2015, of which the company s share would be about 78,000 barrels a day.

Future debottlenecking of both the initial development and expansion will increase output to reach the regulatory capacity of 345,000 barrels a day by 2020.

Bitumen from the Kearl project will be extracted from oil sands produced from open-pit mining operations and processed through a bitumen extraction and froth treatment plant. The product, a blend of bitumen and diluent, is planned to be shipped via pipelines for distribution to North American markets. Diluent is natural gas condensate or other light hydrocarbons added to the crude bitumen to facilitate transportation to market by pipeline.

Kearl will be subject to the revised Alberta generic oil sands royalty regime, which took effect in 2009. Royalty rates are based upon a sliding scale determined by the price of crude oil.

Other oil sands activity

The company is continuing to evaluate other undeveloped, mineable oil sands acreage in the Athabasca region.

Present activities

Review of principal ongoing activities

Cold Lake

During 2011, average net production at Cold Lake was about 120,000 barrels a day and gross production was about 160,000 barrels a day.

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Most of the production from Cold Lake is sold to refineries in the northern U.S. The majority of the remainder of Cold Lake production is shipped to certain of the company s refineries and to third-party Canadian refineries.

The Province of Alberta, in its capacity as lessor of Cold Lake oil sands leases, is entitled to a royalty on production at Cold Lake. Cold Lake is subject to the revised Alberta generic oil sands royalty regime, which took effect in 2009. Royalty rates are based upon a sliding scale determined by the price of crude oil.

Syncrude 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, mines a portion of the Athabasca oil sands deposit. The produced synthetic crude oil is shipped from the Syncrude site to Edmonton, Alberta by Alberta Oil Sands Pipeline Ltd.

In 2011, Syncrude s net production of synthetic crude oil was about 268,000 barrels a day and gross production was about 288,000 barrels a day. The company s share of net production in 2011 was about 67,000 barrels a day.

There are no approved plans for major future expansion projects.

In November 2008, Imperial, along with the other Syncrude joint-venture owners, signed an agreement with the Government of Alberta to amend the existing Syncrude Crown Agreement. Under the amended agreement, starting in 2010 and through 2015 Syncrude will pay the existing Crown royalty rates plus an incremental royalty, the amount of which will be subject to minimum production thresholds, before transitioning to the new generic royalty framework in 2016. Also, beginning January 1, 2009, Syncrude s royalty is based on bitumen value with upgrading costs and revenues excluded from the calculation.

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, automatically renews for successive five-year periods and may be terminated with at least two years prior written notice.

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 about 60 percent of the company s gross production of conventional crude oil. In 2011, gross production of crude oil from Norman Wells was about 11,000 barrels a day. Production was adversely impacted due to third party pipeline reliability issues in the second and third quarter of 2011. 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.

Most of the company s 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.

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.

Delivery commitments

The company is contractually committed to deliver approximately 30 billion cubic feet of natural gas in Canada for the period from 2012 through 2014, which is substantially less than the company s proved natural gas reserves.

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Oil and gas properties, wells, operations, and acreage

Production wells

The company s production of liquids, bitumen and natural gas is derived from wells located exclusively in Canada. The total number of wells capable of production, in which the company had interests at December 31, 2011 and 2010, is set forth in the following table. The statistics in the table are determined in part from information received from other operators.

	Year-ended December 31, 2011				Year-ended December 31, 2010			
	Crude oil		Natural gas		Crude oil		Natural gas	
wells	Gross (a)	Net (b)	Gross (a)	Net (b)	Gross (a)	Net (b)	Gross (a)	Net (b)
Oil and gas (c)	**1,070**	**734**	**2,404**	**847**	883	588	5,372	2,833
Bitumen (c)	**4,068**	**4,068**			4,358	4,358		

(a) Gross wells are wells in which the company owns a working interest.
(b) Net wells are the sum of the fractional working interests owned by the company in gross wells, rounded to the nearest whole number.
(c) Multiple completion wells are permanently equipped to produce separately from two or more distinctly different geological formations. At year-end 2011, the company had an interest in four gross wells with multiple completions (2010 - four gross wells).

The decrease in natural gas wells is primarily attributed to the company s divestments in 2011.

Land holdings

At December 31, 2011 and 2010, the company held the following oil and gas rights, bitumen and synthetic oil leases, all of which are located in Canada, specifically in the Western provinces, in the Canada lands and in the Atlantic offshore:

		Acres					
		Developed		Undeveloped		Total	
thousands of acres		**2011**	2010	**2011**	2010	**2011**	2010
Western provinces:							
Liquids and gas	- gross (a)	**2,156**	2,520	**629**	592	**2,785**	3,112
	- net (b)	**709**	983	**341**	323	**1,050**	1,306
Bitumen	- gross (a)	**103**	103	**636**	645	**739**	748
	- net (b)	**103**	103	**363**	373	**466**	476
Synthetic oil	- gross (a)	**114**	114	**139**	139	**253**	253
	- net (b)	**28**	28	**35**	35	**63**	63
Canada lands (c):							
Liquids and gas	- gross (a)	**4**	4	**2,314**	1,871	**2,318**	1,875
	- net (b)	**2**	2	**722**	500	**724**	502
Atlantic offshore:							
Liquids and gas	- gross (a)	**65**	65	**1,780**	4,469	**1,845**	4,534
	- net (b)	**6**	6	**270**	673	**276**	679
Total (d):	- gross (a)	**2,442**	2,806	**5,498**	7,716	**7,940**	10,522
	- net (b)	**848**	1,122	**1,731**	1,904	**2,579**	3,026

(a) Gross acres include the interests of others.
(b) Net acres exclude the interests of others.
(c) Canada lands include the Arctic Islands, Beaufort Sea/Mackenzie Delta, and other Northwest Territories, Nunavut and Yukon regions.
(d) 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).

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Western provinces

The company s bitumen leases include about 194,000 acres of oil sands leases near Cold Lake and an area of about 34,000 net acres at Kearl. The company has about 89,000 net acres of undeveloped, mineable oil sands acreage in the Athabasca region. In addition, the company also has interests in other bitumen oil sands leases in the Athabasca and Peace River areas totaling about 149,000 net acres. In 2011, the company exchanged oil sands leases in the Athabasca area with a third party, where two leases totaling about 21,000 acres were relinquished in exchange for rights to one strategic lease of about 12,000 acres.

The company s share of Syncrude joint-venture leases covering about 63,000 net acres accounts for the entire synthetic oil acreage.

The company holds interest in an additional 1,050,000 net acres of developed and undeveloped land in Western Canada related to conventional oil and natural gas. Included in this number is a total acreage position of about 170,000 net acres at Horn River, British Columbia. In 2011, the company relinquished a total of about 256,000 net acres in Western Canada.

Canada lands

In the Arctic Islands, the company has an interest in 16 significant discovery licences granted by the Government of Canada. These licences are managed by another company on behalf of all participants and total about 50,000 net acres. The company has not participated in wells drilled in this area since 1984.

Also within the Canada lands, the company holdings in the Mackenzie Delta include majority interests in 21, 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 17, other significant discovery licences managed by others. Total acreage held in the Mackenzie Delta is 184,000 net acres.

In 2011, two exploration licences were acquired from the Government of Canada in the Summit Creek area of central Mackenzie Valley totaling 222,000 net acres.

In 2007, the company acquired a 50 percent interest in an offshore exploration licence in the Beaufort Sea of about 507,000 gross acres. In 2010, the company reduced its interest to 25 percent and acquired a 25 percent interest in another Beaufort Sea exploration licence, as part of a cross-conveyance agreement, of about 500,000 gross acres. The company holds interest in the Beaufort Sea of about 252,000 net acres.

The balance of the Canada lands acreage, 16,000 net acres, consists of multiple leases and significant discovery licences throughout the Northwest Territories and Yukon.

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, managed by others, in 27 significant discovery licences, and six production licences.

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. In early 2009, one exploration licence in its entirety and most of a second exploration licence, for about 1,069,000 gross acres, expired. The remaining exploration licences were consolidated into two exploration licences, for a total of about 627,000 net acres. In 2011, one exploration licence and a portion of the second exploration licence, for about 403,000 net acres, were surrendered. The remaining total Orphan Basin acreage is 224,000 net acres.

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Downstream

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. The Strathcona refinery operates 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 2011, capital expenditures of about $85 million were made at the company s refineries. Capital expenditures focused mainly on refinery projects to improve reliability, feedstock flexibility, energy efficiency and environmental performance.

The approximate average daily volumes of refinery throughput during the five years ended December 31, 2011, and the daily rated capacities of the refineries at December 31, 2011 and 2006, were as follows:

	Refinery throughput (a) Year-ended December 31					Rated capacities at (b) December 31	
thousands of barrels a day	**2011**	2010	2009	2008	2007	**2011**	2006
Strathcona, Alberta	**169**	168	145	155	170	**189**	187
Sarnia, Ontario	**102**	102	100	108	103	**119**	121
Nanticoke, Ontario	**93**	104	94	107	100	**113**	112
Dartmouth, Nova Scotia	**66**	70	74	76	69	**85**	82
Total	**430**	444	413	446	442	**506**	502

(a) Refinery throughput is the volume of crude oil and feedstocks that is processed in the refinery atmospheric distillation units.
(b) 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 85 percent of capacity in 2011, three percent lower than the previous year. The lower rate was primarily a result of higher planned and unplanned maintenance activities.

Distribution

The company maintains a nation-wide distribution system, including 22 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 natural gas liquids and products pipelines in Alberta, Manitoba and Ontario and has interests in the capital stock of one crude oil and two products pipeline companies.

Marketing

The company markets more than 580 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 retail service stations. On average during the year, there were more than 1,800 retail service stations, of which about 480 were company owned or leased, but none of which were company operated. The company continues to improve its Esso retail service station network, providing