IMPERIAL OIL LTD
Form 10-K
February 26, 2010
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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, 2009 **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 2009 second fiscal quarter, the aggregate market value of the voting stock held by non-affiliates of the registrant was Canadian $11,626,102,344 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 12, 2010, was 847,602,581.

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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	**2009**	2008	2007	2006	2005
Rate at end of period	**0.9559**	0.8170	1.0120	0.8582	0.8579
Average rate during period	**0.8793**	0.9335	0.9376	0.8844	0.8276
High	**0.9719**	1.0291	1.0908	0.9100	0.8690
Low	**0.7695**	0.7710	0.8437	0.8528	0.7872

On February 12, 2010, 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 $0.9499 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 supplier of petrochemicals.

Financial information by operating segments (under U.S. GAAP)

millions of dollars	**2009**	2008	2007	2006	2005
External sales (a):					
Upstream	**3,552**	5,819	4,539	4,619	4,702
Downstream	**16,793**	24,049	19,230	18,527	21,793
Chemical	**947**	1,372	1,300	1,359	1,302
	21,292	31,240	25,069	24,505	27,797
Intersegment sales:					
Upstream	**3,328**	5,403	4,146	3,837	3,487
Downstream	**1,535**	2,892	2,305	2,256	2,224
Chemical	**289**	460	335	345	363
Net income (b):					
Upstream	**1,324**	2,923	2,369	2,376	2,008
Downstream	**278**	796	921	624	694
Chemical	**46**	100	97	143	121
Corporate and other (c)	**(69)**	59	(199)	(99)	(223)
	1,579	3,878	3,188	3,044	2,600
Identifiable assets at December 31 (d):					
Upstream	**10,663**	8,758	8,171	7,513	7,289
Downstream	**6,183**	6,038	6,727	6,450	6,257
Chemical	**428**	431	476	504	500
Corporate and other/eliminations	**199**	1,808	913	1,674	1,536
	17,473	17,035	16,287	16,141	15,582
Capital and exploration expenditures:					
Upstream	**2,167**	1,110	744	787	937
Downstream	**251**	232	187	361	478
Chemical	**15**	13	11	13	19

Corporate and other	**5**	8	36	48	41
	2,438	1,363	978	1,209	1,475

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Footnotes to the Financial information by operating segments on the preceding page:

a) Export sales are reported in note 3 to the consolidated financial statements starting on page 87. Total external sales include $4,894 million for 2005 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.
b) 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.
c) Primarily includes interest charges on the debt obligations of the company, interest income and share based incentive compensation expenses.
d) 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 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. This change has no impact on total identifiable assets at December 31, 2005.

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 thereof. Chemical operations consist of the manufacturing and marketing of various petrochemicals.

Upstream

Summary of oil and gas reserves at year-end

The table below summarizes the net oil-equivalent proved reserves for the company, as at December 31, 2009, as detailed in the Oil and gas reserves part of the Financial section, starting on page 107 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, 2009 that would cause a significant change in the estimated proved reserves as of that date.

	Liquids (a)	Natural gas	Synthetic oil	Bitumen	Total oil-equivalent basis
	millions of barrels	billions of cubic feet	millions of barrels	millions of barrels	millions of barrels
Net proved reserves:					
Developed	**62**	**526**	**691**	**468**	**1,309**
Undeveloped	**1**	**64**		**1,193**	**1,204**
Total net proved	**63**	**590**	**691**	**1,661**	**2,513**

a) Liquids include crude oil, condensate and natural gas liquids (NGLs).

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 2009 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.

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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. 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. This group also maintains the official company reserve estimates for Imperial s proved reserves of crude oil and natural gas liquids, synthetic oil, bitumen, and natural gas. 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. Our internal reserves evaluation staff consists of about 63 persons with an average of approximately 16 years of relevant experience in evaluating reserves, of whom about 36 persons are qualified reserves evaluators for purposes of Canadian securities regulatory requirements. Our internal reserves evaluation management team is made up of about 18 persons with an average of approximately 16 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, 2009, approximately 48 percent of the company s proved reserves were proved undeveloped reserves reflecting volumes of 1,204 million oil-equivalent barrels. Nearly all of those undeveloped reserves are associated with either the Kearl project or Cold Lake field.

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. Imperial has a disciplined investment strategy and many major fields require a significant lead-time in order to be developed. Imperial made investments of about $1.4 billion during the year to progress the development of reported proved undeveloped reserves. Notably, the company spent about $1.1 billion on progressing the Kearl project in 2009.

Imperial has had a significant ongoing drilling program at Cold Lake since 1978, and in 2009 made investments of about $250 million to progress the development of proved undeveloped reserves. Proved undeveloped reserves at Cold Lake are associated with the ongoing drilling program.

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Oil and gas production, production prices and production costs

The company s average daily oil production by final products sold during the three years ended December 31, 2009, was as follows. All reported production volumes were from Canada.

thousands of barrels a day		2009	2008	2007
Liquids:	- gross (a)	**33**	37	45
	- net (b)	**26**	27	33
Bitumen (c):	- gross (a)	**141**	147	154
	- net (b)	**120**	124	130
Synthetic oil (d):	- gross (a)	**70**	72	76
	- net (b)	**65**	62	65
Total:	- gross (a)	**244**	256	275
	- net (b)	**211**	213	228

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 2009, the most significant reason for lower liquids production volume was natural decline in Western Canada reservoirs. Bitumen production at Cold Lake declined due to the cyclic nature of production and well repairs in the northern part of the field. Drilling and steaming activities have since resumed in this area, and production is expected to return to normal levels. Gross synthetic oil production at Syncrude was also lower as planned maintenance activities in the first half of 2009, which included design modifications to improve long-term operational performance, contributed to the reduced production for the full year in 2009. Net synthetic oil production at Syncrude was higher due to lower royalties.

In 2008, the liquids production volume was lower primarily due to the completion of the Wizard Lake blow down. Bitumen production at Cold Lake declined due to steam cycle timing and higher royalties. Synthetic oil production at Syncrude declined primarily due to increased planned and unplanned maintenance activities, including continuing work to improve reliability performance.

The company s average daily production and sales of natural gas during the three years ended December 31, 2009 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.

Average daily production and sales of natural gas

millions of cubic feet a day	2009	2008	2007
Gross production (a) (b):	**295**	310	458
Net production (c):	**274**	249	404
Sales (d):	**272**	288	407

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 2009, the lower gross gas production volume was primarily a result of natural reservoir decline. Net production volumes were higher due to lower royalties.

In 2008, the most significant reason for lower natural gas production volume was the completion of the Wizard Lake blow down.

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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.

Total average daily oil-equivalent basis production

thousands of barrels a day	**2009**	2008	2007
Total production oil-equivalent basis:			
- gross (a)	**293**	308	351
- net (b)	**257**	255	295

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.

The company s average unit sales price and average unit production costs by product type for the three years ended December 31, 2009, were as follows:

Average unit sales price

dollars a barrel	**2009**	2008	2007
Liquids	**53.91**	84.67	62.31
Synthetic oil	**69.69**	106.61	79.10
Bitumen	**51.81**	69.04	39.77
dollars per thousand cubic feet			
Natural gas	**4.11**	8.69	6.95

Average unit production costs

dollars a barrel	**2009**	2008	2007
Bitumen	**17.17**	21.09	14.44
Total oil-equivalent basis (a)	**23.66**	25.25	17.10

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 2009, unit production costs decreased on a net basis. Higher net volumes due to lower price sensitive royalties more than offset increased spending.

In 2008, unit production costs were higher, primarily as a result of lower gas and liquids volumes due to production decline at Wizard Lake and the unfavorable impact on higher prices on royalty rates and net volumes.

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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.

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, 2009.

wells	**2009**	2008	2007
Net productive exploratory:			
Oil and gas	**2**		
Bitumen			
Net dry exploratory:			
Oil and gas			
Bitumen			
Net productive development:			
Oil and gas	**218**	147	183
Bitumen	**60**	70	188
Net dry development:			
Oil and gas			
Bitumen			
Total	**280**	217	371

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.

In 2008, 70 bitumen development wells were drilled to add new productive capacity from undeveloped areas of existing phases at Cold Lake. In addition, 146 gas development wells were drilled in 2008 adding productivity primarily in the shallow gas area. Additionally, one oil development well was drilled in Norman Wells. In 2007, 188 bitumen development wells were drilled to add new productive capacity from undeveloped areas of existing phases at Cold Lake. In addition, 183 gas development wells were drilled in 2007 adding productivity primarily in the shallow gas area.

Wells drilling

At December 31, 2009, the company was participating in the drilling of the following exploratory and development wells. All wells were located in Canada.

	2009	
wells	Gross	Net
Oil and gas	**3**	**2**
Bitumen	**20**	**20**
Total	**23**	**22**

Exploratory and development activities regarding oil and gas resources

Cold Lake

In 2009, the company spent about $300 million on capital and exploration expenditures at Cold Lake. To maintain production at Cold Lake, capital expenditures for additional production wells and associated facilities will be required periodically. In 2009, the company executed a development drilling program of 60 wells on existing phases. In 2010, a development drilling program is planned within the approved development area to add productive capacity from undeveloped areas of existing Cold Lake phases. In addition, planning and design work is progressing on the Nabiye project, the next phase of expansion at Cold Lake that has the potential to add about 30,000 barrels a day of production before royalties.

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

Western provinces

A four-well (gross) winter exploration drilling program at the company s Horn River shale gas acreage was completed in 2009. Work is underway on a production pilot to evaluate reservoir productivity and scale.

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 with an NEB decision expected in 2010.

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, the company began a data collection program to support environmental studies and safe exploration drilling operations.

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. Drilling of an exploration well was concluded in early 2007. In 2009, the company participated in a remote reservoir resistivity survey of the area. A second exploration well has been approved by co-venturers for drilling in 2010.

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 heavy oil. 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 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.

Kearl will be developed in phases. Bitumen 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, will 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.

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 license in 2008, which permits the project to mine oil sands and produce bitumen from approved development areas on oil sands leases.

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The first phase of the Kearl project was approved by the company s board in May 2009. Production from the first phase 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. Start up is expected in 2012. About $2 billion had been spent on the project as at the end of 2009, of which the company s share was about $1.5 billion. In 2009, pipeline transportation was secured, infrastructure construction continued and more than half of the detailed engineering was completed.

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 2009, average net production at Cold Lake was about 120,000 barrels per day and gross production was about 141,000 barrels per day.

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 a third-party crude bitumen upgrader in Lloydminster, Saskatchewan.

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 sand 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 2009, Syncrude s net production of synthetic crude oil was about 259,000 barrels per day and gross production was about 280,000 barrels per day. The company s share of net production in 2009 was about 65,000 barrels per 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 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.

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 joint venture owners as the result of the non-deductibility from the income of the joint venture owners 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. The final determination of the remission amount applicable to Syncrude operations up to 2003 is a matter currently being litigated with the Government of Canada.

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.

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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 56 percent of the company s net production of conventional crude oil (approximately 60 percent of gross production). In 2009, net production of crude oil was about 11,000 barrels per day and gross production was about 15,000 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 2009, those costs were about $33 million.

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 has no material commitments to provide a fixed and determinable quantity of oil or gas in the near future under existing contracts or agreements.

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, 2009 and 2008, is set forth in the following table. The statistics in the table are determined in part from information received from other operators.

	Year-ending December 31, 2009				Year-ending December 31, 2008			
	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)	**937**	**627**	**5,479**	**2,894**	906	601	5,186	2,768
Bitumen (c)	**4,028**	**4,028**			4,243	4,243		

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 2009, the company had an interest in four gross wells with multiple completions.

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Land holdings

At December 31, 2009 and 2008, 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		**2009**	2008	**2009**	2008	**2009**	2008
Western provinces:							
Liquids and gas	- gross (a)	**2,590**	2,566	**568**	435	**3,158**	3,001
	- net (b)	**986**	1,004	**318**	251	**1,304**	1,255
Bitumen	- gross (a)	**103**	103	**645**	612	**748**	715
	- net (b)	**103**	103	**373**	364	**476**	467
Synthetic oil	- gross (a)	**114**	114	**139**	137	**253**	251
	- net (b)	**28**	28	**35**	35	**63**	63
Canada lands (c):							
Liquids and gas	- gross (a)	**37**	37	**1,343**	1,343	**1,380**	1,380
	- net (b)	**5**	5	**499**	499	**504**	504
Atlantic offshore:							
Liquids and gas	- gross (a)	**65**	65	**4,469**	6,012	**4,534**	6,077
	- net (b)	**6**	6	**673**	1,308	**679**	1,314
Total (d):	- gross (a)	**2,909**	2,885	**7,164**	8,539	**10,073**	11,424
	- net (b)	**1,128**	1,146	**1,898**	2,457	**3,026**	3,603

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).

Western provinces

The company s bitumen leases include about 194,000 net acres of oil sands leases near Cold Lake and an area of about 48,000 net acres at Kearl. In 2009, the company acquired approximately 8,000 net acres of additional undeveloped bitumen acreage adjacent to the company s existing Firebag North lands in the Athabasca area. The company now has about 77,000 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 170,000 net 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 1,304,000 net acres of developed and undeveloped land in Western Canada related to conventional oil and natural gas. Included in this number is approximately 79,000 net acres acquired in 2009 in the natural gas prone Horn River area of British Columbia, creating a total net acreage position of about 155,000 acres at Horn River.

Canada lands

In the Arctic Islands, the company has an interest in 16 Significant Discovery Licences and one production licence granted by the Government of Canada. These licences are managed by another company on behalf of all participants and total 387,000 gross acres. The company has not participated in wells drilled in this area since 1984.

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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 gross acres held in the Mackenzie Delta are 421,000.

In 2007, the company acquired a 50 percent interest in an exploration licence in the Beaufort Sea of about 507,000 gross acres.

Atlantic offshore

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

In 2008, one exploration licence in the Sable Island area, in which the company had a 20 percent interest, for about 52,000 gross acres was allowed to expire. Also in 2008, one exploration licence in which the company had a 70 percent interest for about 279,000 gross acres farther offshore in deeper water was allowed to expire. The company is not planning further exploration in these areas.

In early 2004, the company acquired a 25 percent interest in eight deep-water exploration licences offshore Newfoundland in the Orphan Basin for about 5,251,000 gross acres. In February 2005, the company reduced its interest to 15 percent through an agreement with another company. 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 4.2 million gross acres.

In 2009, in the Laurentian Basin area, offshore Newfoundland and Labrador, a single exploration licence of 474,000 gross acres was allowed to expire. The company held a 100 percent interest.

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

In 2009, capital expenditures of about $160 million were made at the company s refineries. About 70 percent of those expenditures were on environmental and safety initiatives with the remaining expenditures being primarily on capacity and efficiency improvements.

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The approximate average daily volumes of refinery throughput during the five years ended December 31, 2009, and the daily rated capacities of the refineries at December 31, 2009 and 2004, were as follows:

	Average daily volumes of refinery throughput (a) Year-ended December 31					Daily rated capacities at (b) December 31	
thousands of barrels	**2009**	2008	2007	2006	2005	**2009**	2004
Strathcona, Alberta	**145**	155	170	160	174	**187**	187
Sarnia, Ontario	**100**	108	103	111	106	**121**	121
Nanticoke, Ontario	**94**	107	100	94	108	**112**	112
Dartmouth, Nova Scotia	**74**	76	69	77	79	**82**	82
Total	**413**	446	442	442	466	**502**	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 82 percent of capacity in 2009, seven percent lower than the previous year. Production gains from operating and reliability improvements through the year were offset by the impact of declining economic conditions that did not support running the refineries to full capacity.

Distribution

The company maintains a nation-wide distribution system, including 24 primary terminals, to handle bulk and packaged petroleum products moving from refineries to market by pipeline, tanker, rail and road transport. The company owns and operates crude oil, natural gas liquids and products pipelines in Alberta, Manitoba and Ontario and has interests in the capital stock of one crude oil and two products pipeline companies.

Marketing

The company markets more than 650 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 about 1,850 retail service stations, of which about 540 were company owned or leased, but none of which were company operated. The company continues to improve its Esso retail service station network, providing more customer services such as car washes and convenience stores, primarily at high volume sites in urban centres.

The Canadian farm, residential heating and small commercial markets are served through about 85 sales facilities. The company also sells petroleum products to large industrial and commercial accounts as well as to other refiners and marketers.

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The approximate daily volumes of net petroleum products (excluding purchases/sales contracts with the same counterparty) sold during the five years ended December 31, 2009, are set out in the following table:

thousands of barrels a day	**2009**	2008	2007	2006	2005
Gasolines	**200**	204	208	206	210
Heating, diesel and jet fuels	**143**	157	164	166	169
Heavy fuel oils	**27**	30	33	32	38
Lube oils and other products	**39**	47	43	49	48
Net petroleum product sales	**409**	438	448	453	465

The total domestic sales of petroleum products, as a percentage of total sales of petroleum products during the five years ended December 31, 2009, were as follows:

percentage	**2009**	2008	2007	2006	2005
Domestic petroleum product sales as a percentage of total petroleum product sales	**90.3**	93.0	94.8	95.1	95.3

The company continues to evaluate and adjust its Esso retail service station and distribution system to increase productivity and efficiency. During 2009, the company closed or debranded about 80 Esso retail service stations, about 25 of which were company owned, and added about 50 sites. The company s average annual throughput in 2009 per Esso retail service station was about 25 thousand barrels (3.9 million litres), an increase of about one thousand barrels (0.2 million litres). Average throughput per company owned or leased Esso retail service station was about 44 thousand barrels (7.0 million litres) in 2009, an increase of about two thousand barrels (0.3 million litres) from 2008.

Chemical

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

The company s average daily sales of petrochemicals during the five years ended December 31, 2009, were as follows:

thousands of tonnes a day	**2009**	2008	2007	2006	2005
Total average daily sales of petrochemicals	**2.8**	2.8	3.1	3.0	3.0

Research

In 2009, the company s research expenditures in Canada, before deduction of investment tax credits, were $78 million, as compared with $117 million in 2008, and $83 million in 2007. Those funds were used mainly for developing improved crude bitumen recovery methods and refinery processes, and supporting the lubricants business.

A research facility to support the company s Upstream operations is located in Calgary, Alberta. Research in these laboratories is aimed at developing new technology for the production and processing of crude bitumen. About 40 people were involved in this type of research in 2009. The company also participated in bitumen recovery and processing research for oil sands development through its interest in Syncrude, which maintains research facilities in Edmonton, Alberta and through research arrangements with others.

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In company laboratories in Sarnia, Ontario, research and advanced technical support is mainly conducted on the development and support of lubricants and fuels products and processes. About 105 people were employed in this type of research and advanced technical support at the end of 2009. Also in Sarnia, there are about eight people engaged in new product development for the company s and Exxon Mobil Corporation s polyethylene injection and rotational molding businesses.

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

Environmental protection

The company is concerned with and active in protecting the environment in connection with its various operations. The company works in cooperation with government agencies, industry associations and communities to deal with existing, and to anticipate potential, environmental protection issues. In the past five years, the company has made capital and operating expenditures of about $3.0 billion on environmental protection and facilities. In 2009, the company s environmental capital and operating expenditures totaled approximately $770 million, which was spent primarily on emissions reductions at company owned facilities and Syncrude, remediation of idled facilities and operations, as well as on protection of freshwater near Imperial facilities. Capital and operating expenditures relating to environmental protection are expected to be about $790 million in 2010.

Human resources

At December 31, 2009, the company employed 5,015 persons on a full-time basis, compared with about 4,850 at the end of 2008 and 4,800 at the end of 2007. About nine percent of the company s employees are members of unions. The company continues to maintain a broad range of benefits, including health, dental, disability and survivor benefits, vacation, savings plan and pension plan.

Competition

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

Government regulation

Petroleum and natural gas rights

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

Crude oil

Production

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

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Exports

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

Natural gas

Production

The maximum allowable gross production of natural gas from wells in Canada is subject to limitations by various regulatory authorities. These limitations are to ensure oil recovery is not adversely impacted by accelerated gas production practices. These limitations do not impact gas reserves, only the timing of production of the reserves, and did not have a significant impact on 2009 gas production rates.

Exports

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

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

Royalties

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

Different royalties are imposed by the Government of Canada and each of the producing provinces. Royalties imposed on crude oil, natural gas and natural gas liquids vary depending on a number of parameters, including well production volumes, selling prices and recovery methods. For information with respect to royalty rates for Norman Wells, Cold Lake, Syncrude and Kearl, see Upstream section under Item 1.

Investment Canada Act

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

The Act also requires notification of the establishment of new unrelated businesses in Canada by entities not controlled by Canadians, but does not require Government of Canada approval except when the new business is related to Canada s cultural heritage or national identity. The Government of Canada is also authorized, through recent amendments to the Act, to take any measures that it considers advisable to protect national security, including the outright prohibition of a foreign investment in Canada. By virtue of the majority stock ownership of the company by Exxon Mobil Corporation, the company is considered to be an entity which is not controlled by Canadians.

The company online

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

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Item 1A. Risk factors

Volatility of oil and natural gas prices

The company s results of operations and financial condition are dependent on the prices it receives for its oil and natural gas production. Crude oil and natural gas prices are determined by global and North American markets and are subject to changing supply and demand conditions. These can be influenced by a wide range of factors including economic conditions, international political developments and weather. In the past, crude oil and natural gas prices have been volatile, and the company expects that volatility to continue. Any material decline in oil or natural gas prices could have a material adverse effect on the company s operations, financial condition, proven reserves and the amount spent to develop oil and natural gas reserves.

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

Industry crude oil and natural gas commodity prices and petroleum and chemical product prices are commonly benchmarked in U.S. dollars. The majority of Imperial s sales and purchases are related to these industry U.S. dollar benchmarks. As the company records and reports its financial results in Canadian dollars, to the extent that the Canadian/U.S. dollar exchange rate fluctuates, the company s earnings will be affected.

The company does not use derivative instruments to speculate on the future direction of currency or commodity prices.

Competitive factors

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

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

Environmental risks

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

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

Climate change

In April 2007, the Government of Canada announced its intent to introduce a set of regulations to limit emissions of greenhouse gas and air pollutants from major industrial facilities in Canada, although the details of the regulations have not been finalized. In the fall of 2009, the Government further expressed its intent that Canadian policy in this area be aligned with that of the U.S., which also remains under development. Consequently, attempts to assess the impact on the company are premature. The company will continue to monitor the development of legal requirements in this area.

In the Province of Alberta, regulations governing greenhouse gas emissions from large industrial facilities came into effect July 1, 2007. These regulations cover industrial facilities emitting more than 100,000 tonnes (carbon dioxide equivalent) of greenhouse gas emissions annually and require a reduction by 12 percent in the greenhouse gas emissions per unit of production from each facility s average annual intensity over the period 2003 through 2005. Allowed compliance measures include participation in an Alberta emission-trading system or payment (at a rate of $15 per excess tonne of emissions) to Alberta s Climate Change and Emissions Management Fund. Impact on the overall operations of the company has not been material.

The Province of British Columbia introduced a carbon tax in 2008 applying to purchases of hydrocarbon fuels and emissions of greenhouse gases. The applicable tax rate was increased from $10 per tonne of carbon dioxide to $15 in 2009, and further annual increases of $5 a tonne to a level of $30 a tonne are planned. It is the current policy of the government of British Columbia. to offset revenues from this tax by reductions in corporate and personal income taxes. Impacts on the company and its operations have not been and are not expected to be material.

The provinces of Ontario and Quebec have passed legislation authorizing the issuing of regulations for the creation of a provincial cap-and-trade system controlling greenhouse gas emissions from industrial facilities. However, details on such possible regulations have not been provided and consequently attempts to assess any impacts on the company are premature.

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The Province of British Columbia has introduced Low Carbon Fuel Standard (LCFS) regulations requiring suppliers of transportation fuels to report the life cycle greenhouse gas emissions per unit of energy of fuels sold in British Columbia, and beginning in 2011 to reduce these emissions by an increasing amount each year. California has introduced similar requirements and some other U.S. states are considering comparable measures. Such measures may have implications for the company s marketing in British Columbia or the U.S. of oil sands production or of products derived from them, but the impact cannot be determined at this time.

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

Further federal or provincial legislation or regulation controlling greenhouse gas emissions could occur and result in increased capital expenditures and operating costs, affect demand and have a material adverse effect on the company s financial condition or results of operations, but any potential impact cannot be estimated at this time.

Other regulatory risk

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

Need to replace reserves

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

Other business risks

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

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Uncertainty of reserve estimates

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

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

Project factors

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

Item 1B. Unresolved staff comments

Not applicable.

Item 2. Properties

Reference is made to Item 1 above.

Item 3. Legal proceedings

Not applicable.

Item 4. Submission of matters to a vote of security holders

Not applicable.

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PART II

Item 5. Market for registrant s common equity, related stockholder matters and issuer purchases of equity securities

Information for security holders outside Canada

Cash dividends paid to shareholders resident in countries with which Canada has an income tax convention are usually subject to a Canadian nonresident withholding tax of 15 percent.

The withholding tax is reduced to five percent on dividends paid to a corporation resident in the U.S. that owns at least 10 percent of the voting shares of the company.

Imperial is a qualified foreign corporation for purposes of the reduced U.S. capital gains tax rates (15 percent and as low as zero percent for certain individuals), which are applicable to dividends paid by U.S. domestic corporations and qualified foreign corporations.

There is no Canadian tax on gains from selling shares or debt instruments owned by nonresidents not carrying on business in Canada.

Reference is made to the Quarterly financial and stock trading data portion of the Financial section on page 109 of this report.

As of February 12, 2010 there were 13,123 holders of record of common shares of the company.

During the period October 1, 2009 to December 31, 2009, the company issued 16,350 common shares to employees or former employees outside the U.S. for $15.50 per share upon the exercise of stock options. During the period October 1, 2009 to December 31, 2009, the company issued 4,320 shares to employees or former employees outside the U.S. under its restricted stock unit plan. These issuances were not registered under the *Securities Act* in reliance on Regulation S thereunder.

On June 23, 2009, the company announced by news release that it had received final approval from the Toronto Stock Exchange for a new normal course issuer bid and will continue its share repurchase program. The new program enables the company to repurchase up to a maximum of 42,380,326 common shares, including common shares purchased for the company s employee savings plan and the company s employee retirement plan and from Exxon Mobil Corporation during the period of June 25, 2009 to June 24, 2010. If not previously terminated, the program will end on June 24, 2010.

Issuer purchases of equity securities

period	Total number of shares purchased	Average price paid per share ($)	Total number of shares purchased as part of publicly announced plans or programs	Maximum number (or approximate dollar value) of shares that may yet be purchased under the plans or programs
October 2009 (October 1 - October 31)		**n/a**		**42,037,559**
November 2009 (November 1 - November 30)	**9,000**	**40.89**	**9,000**	**41,946,887**
December 2009 (December 1 - December 31)	**27,420**	**40.25**	**27,420**	**41,835,978**

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Item 6. Selected financial data

millions of dollars	**2009**	2008	2007	2006	2005
Operating revenues (a)	**21,292**	31,240	25,069	24,505	27,797
Net income	**1,579**	3,878	3,188	3,044	2,600
Total assets at year-end	**17,473**	17,035	16,287	16,141	15,582
Long term debt at year-end	**31**	34	38	359	863
Total debt at year-end	**140**	143	146	1,437	1,439
Other long term obligations at year-end	**2,839**	2,254	1,914	1,683	1,728
dollars					
Net income/share basic (b)	**1.86**	4.39	3.43	3.12	2.54
Net income/share diluted (b)	**1.84**	4.36	3.41	3.11	2.53
Dividends/share (b)	**0.40**	0.38	0.35	0.32	0.31

a) Operating revenues include $4,894 million for 2005 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.

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

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

Item 7. Management s discussion and analysis of financial condition and results of operations

Reference is made to the section entitled Management discussion and analysis of financial condition and results of operations in the Financial section, starting on page 63 of this report.

Item 7A. Quantitative and qualitative disclosures about market risks

Reference is made to the section entitled Market risks and other uncertainties in the Financial section of this report, page 73. All statements other than historical information incorporated in this Item 7A are forward-looking statements. The actual impact of future market changes could differ materially due to, among other things, factors discussed in this report.

Item 8. Financial statements and supplementary data

Reference is made to the following financial information in the Financial section of this report:

Consolidated financial statements, together with the report thereon of PricewaterhouseCoopers LLP (PwC) dated February 26, 2010, beginning with the section entitled Independent auditors report on page 78 and continuing through note 15, Transactions with related parties on page 103; Supplemental information on oil and gas exploration and production activities (unaudited) starting on page 104, and Quarterly financial and stock trading data (unaudited) on page 109.

Item 9. Changes in and disagreements with accountants on accounting and financial disclosure

None.

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Item 9A. Controls and procedures

As indicated in the certifications in Exhibit 31 of this report, the company s principal executive officer and principal financial officer have evaluated the company s disclosure controls and procedures as of December 31, 2009. Based on that evaluation, these officers have concluded that the company s disclosure controls and procedures are effective in ensuring that information required to be disclosed by the company in the reports that it files or submits under the Securities Exchange Act of 1934, as amended, is accumulated and communicated to them in a manner that allows for timely decisions regarding required disclosures and are effective in ensuring that such information is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms.

Reference is made to page 77 of this report for Management s report on internal control over financial reporting and page 78 for the Independent auditors report of the independent registered public accounting firm on the company s internal control over financial reporting as of December 31, 2009.

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

Item 9B. Other information

None.

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PART III

Item 10. Directors, executive officers and corporate governance

The company currently has eight directors. Each director is elected to hold office until the close of the next annual meeting. Each of the seven individuals listed below have been nominated for election at the annual meeting of shareholders to be held April 29, 2010. All of the nominees, except for D.S. Sutherland, are now directors and have been since the dates indicated. R. Phillips is currently a director and is not standing for re-election in 2010 as he will reach the company s mandatory retirement age for directors in 2010. R. Phillips is currently a member of audit committee; member of executive resources committee; member of environment, health and safety committee; member of nominations and corporate governance committee and a member of the Imperial Oil Foundation board of directors. P.A. Smith is currently a director and is not standing for re-election in 2010, as he has announced he will be retiring from the company effective April 30, 2010. P.A. Smith is currently a member of the Imperial Oil Foundation board of directors.

The following chart provides information on the seven nominees proposed for election to the board of directors of the company.

Name and current principal occupation or employment	Last major position or office with the company or Exxon Mobil Corporation	Director since	Holdings (d)(e)(f)	
K.T. (Krystyna) Hoeg Retired president and chief executive officer, Corby Distilleries Limited (a)(c)		May 1, 2008	Common shares of Imperial Oil Limited	**0**
			Deferred share units of Imperial Oil Limited	**5,005**
			Restricted stock units of Imperial Oil Limited	**4,000**
			Shares of Exxon Mobil Corporation	**0**
B.H. (Bruce) March Chairman, president and chief executive officer, Imperial Oil Limited	President, Imperial Oil Limited, Calgary, Alberta	January 1, 2008	Common shares of Imperial Oil Limited	**5,000**
			Deferred share units of Imperial Oil Limited	**0**
			Restricted stock units of Imperial Oil Limited	**86,600**
			Shares of Exxon Mobil Corporation (g)	**71,066**

J.M. (Jack) Mintz Palmer Chair in Public Policy for the University of Calgary (a)(c)		April 21, 2005	Common shares of Imperial Oil Limited	**1,000**
			Deferred share units of Imperial Oil Limited	**6,147**
			Restricted stock units of Imperial Oil Limited	**9,000**
			Shares of Exxon Mobil Corporation	**0**
R.C. (Robert) Olsen Executive vice-president, ExxonMobil Production Company (b)(c)	Chairman and production director, ExxonMobil International Limited, London, England	May 1, 2008	Common shares of Imperial Oil Limited	**6,000**
			Deferred share units of Imperial Oil Limited	**0**
			Restricted stock units of Imperial Oil Limited	**0**
			Shares of Exxon Mobil Corporation (g)	**307,562**

(Table continued on next page)

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Name and current principal occupation or employment	Last major position or office with the company or Exxon Mobil Corporation	Director since	Holdings (d)(e)(f)	
D.S. (David) Sutherland Retired president and chief executive officer, IPSCO Inc. (steel manufacturing)			Common shares of Imperial Oil Limited	**15,000**
			Deferred share units of Imperial Oil Limited	**0**
			Restricted stock units of Imperial Oil Limited	**0**
			Shares of Exxon Mobil Corporation	**5,450**
S.D. (Sheelagh) Whittaker Corporate director (a)(c)		April 19, 1996	Common shares of Imperial Oil Limited	**9,000**
			Deferred share units of Imperial Oil Limited	**36,795**
			Restricted stock units of Imperial Oil Limited	**12,000**
			Shares of Exxon Mobil Corporation	**0**
V.L. (Victor) Young Corporate director (a)(c)		April 23, 2002	Common shares of Imperial Oil Limited	**12,750**
			Deferred share units of Imperial Oil Limited	**6,864**
			Restricted stock units of Imperial Oil Limited	**12,000**
			Shares of Exxon Mobil Corporation	**0**

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

b) Member of executive resources committee; member of environment health and safety committee; and member of nominations and corporate governance committee.

c) Member of Imperial Oil Foundation board of directors.

d) The information includes the beneficial ownership of common shares of Imperial Oil Limited and shares of Exxon Mobil Corporation, which information not being within the knowledge of the company, has been provided by the nominees individually.

e) The company s plans for restricted stock units and deferred share units is described starting on pages 47 and 46 for nonemployee directors and on pages 32 and 34 for selected employees.

f) The numbers for the company s restricted stock units and deferred share units represent the total of the restricted stock units and deferred share units received in 2006, 2007, 2008 and 2009 after the three-for-one share split in May 2006, plus three times the number of restricted stock units and deferred share units granted before the share split and still held by the director. The numbers for Exxon Mobil Corporation restricted stock include restricted stock and restricted stock units granted under its restricted stock plan, which is similar to the company s restricted stock unit plan.

g) B.H. March holds 35,516 common shares and 35,550 restricted shares and restricted stock units of Exxon Mobil Corporation. R.C. Olsen holds 125,562 common shares and 182,000 restricted shares and restricted stock units of Exxon Mobil Corporation.

The ages of the directors, nominees for election as directors, and the named executive officers of the company are: R.L. Broiles 52, C.W. Erickson 50, K.T. Hoeg 60, B.H. March 53, J.M. Mintz 58, R.C. Olsen 59, R. Phillips 70, P.A. Smith 56, S.M. Smith 52, D.S. Sutherland 60, S.D. Whittaker 62, V.L. Young 64.

Certain of the directors and nominees for election as directors hold positions as directors of other Canadian and U.S. reporting issuers as follows:

Name	Other reporting issuers of which director is also a director
K.T. Hoeg	Sun Life Financial Inc.
	Shoppers Drug Mart Corporation
	Canadian Pacific Railway Limited
	Canadian Pacific Railway Company
	Cineplex Galaxy Income Fund
J.M. Mintz	Brookfield Asset Management Inc.
	Morneau Sobeco Income Fund
R. Phillips	Canadian Pacific Railway Limited
	Canadian Pacific Railway Company
	Cliffs Natural Resources Inc.
	The Toronto-Dominion Bank
D.S. Sutherland	GATX Corporation
	United States Steel Corporation
	ZCL Composites Inc.
S.D. Whittaker	Standard Life plc
V.L. Young	Bell Aliant Regional Communications Income Fund
	BCE Inc.
	Royal Bank of Canada

All of the directors and nominees for election as directors, except for K.T. Hoeg, J.M. Mintz, and D.S. Sutherland have been engaged for more than five years in their present principal occupations or in other executive capacities with the same firm or affiliated firms. During the five preceding years, K.T. Hoeg was president and chief executive officer of Corby Distilleries Limited until she retired in February 2007, J.M. Mintz was president and chief executive officer of The C.D. Howe Institute until he retired in July 2006 and D.S. Sutherland was president and chief executive officer of Ipsco Inc. until he retired in July 2007.

In addition to the named executive officers listed on page 28, the following are also executive officers of the company as of February 12, 2010.

Name and office	Office held since	Age
Sean R. Carleton	February 1, 2008	51
Controller		
Phil Dranse	August 1, 2008	56

Assistant treasurer		
Marvin E. Lamb	December 1, 2001	54
Director, corporate tax		
Brian W. Livingston	August 1, 2004	55
Vice-president, general counsel and corporate secretary		

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

Audit committee

The company has an audit committee of the board of directors. The following directors are the members of the audit committee: K.T. Hoeg, J.M. Mintz, R. Phillips, S.D. Whittaker and V.L. Young (chair).

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Audit committee financial expert

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

Code of ethics

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

Item 11. Executive compensation

Named executive officers of the company

The named executive officers of the company at the end of 2009 were:

B.H. (Bruce) March, Chairman, president and chief executive officer;

P.A. (Paul) Smith, Senior vice-president, finance and administration, and treasurer;

R.L. (Randy) Broiles, Senior vice-president, resources division;

C.W. (Chris) Erickson, Vice-president and general manager, refining and supply; and

S.M. (Simon) Smith, Vice-president and general manager, fuels marketing.

Executive resources committee

The executive resources committee of the board of directors is composed of the five independent directors and R.C. Olsen, who is employed by ExxonMobil Production Company. The executive resources committee is responsible for corporate policy on compensation and for specific decisions on the compensation of the chief executive officer and key senior executives and officers reporting directly to that position. In addition to compensation matters, the committee is also responsible for succession plans and appointments to senior executive and officer positions, including the chief executive officer.

During 2009, the membership of the executive resources committee was as follows: R. Phillips (chair), V.L. Young (vice-chair), K.T. Hoeg, J.M. Mintz, R.C. Olsen and S.D. Whittaker.

B.H. March periodically attends meetings at the request of the committee.

Report of executive resources committee on executive compensation

The executive resources committee of the board of directors has reviewed and discussed the Compensation discussion and analysis for 2009 with management of the company. Based on that review and discussion, the committee recommended to the board that the Compensation discussion and analysis be included in the company s management proxy circular for the 2010 annual meeting of shareholders.

Submitted on behalf of the executive resources committee:

R. Phillips (chair) J.M. Mintz

V.L. Young (vice-chair)	R.C. Olsen
K.T. Hoeg	S.D. Whittaker

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Compensation discussion and analysis

Overview

Providing energy to meet Canada s demands is a complex business. The company meets this challenge by taking a long-term view to managing its business rather than reacting to short-term business cycles. As such, the compensation program of the company aligns with this long-term business approach and key business strategies as outlined below.

Business environment

- Large capital expenditures with long investment periods;
- Complex operating and financial risks;
- National scope of company operations; and
- Commodity-based cyclical product prices.

Key business strategies

- Grow profitable sales volumes;
- Disciplined, selective and long-term focus on improving the productivity of the company s asset mix;
- Flawless execution; and
- Best-in-class cost structure to ensure industry-leading returns on capital and superior cash flow.

Focus on these key strategies for the business is a company priority and ensures long-term growth in shareholder value.

Key elements of the compensation program

The key elements of the company s compensation program and staffing objectives that support the business environment and key business strategies are:

- long-term career orientation with high individual performance standards (see page 30);
- base salary that rewards individual performance and experience (see page 31);
- annual bonus grants based on business performance, as well as individual performance and experience (starting on page 31);
- payment of a large portion of executive compensation in the form of restricted stock units with lengthy vesting periods (starting on page 32); and
- retirement benefits (pension and savings plans) that provide for financial security after employment (starting on page 34).

The company s executive compensation program is designed to:

- reinforce the company s orientation toward career employment and individual performance;
- acknowledge the long-term nature of the company s business;
- reinforce its philosophy that the experience, skill and motivation of the company s executives are significant determinants of future business success; and
- ensure alignment with long-term shareholder interests.

The compensation program emphasizes competitive salaries and performance-based incentives as the primary instruments to attract, develop and retain key personnel.

Other supporting compensation and staffing practices

- A long established program of management development and succession planning is in place to reinforce a career orientation and ensure continuity of leadership.
- All executives participate in common programs (the same salary, incentive and retirement programs). Within these programs, the compensation of executives is differentiated based on individual performance assessment, level of responsibility and individual experience. All senior executives on loan assignment from ExxonMobil participate in common programs, as well, which are administered by ExxonMobil.
- Substantial amounts of executive compensation for the named executive officers are at risk of forfeiture if the executive engages in activity that is detrimental to the company, including material negative restatement of financial or operating results.

- Inappropriate risk taking is discouraged by requiring senior executives to hold a substantial portion of their equity incentive award for a long period of time and in some cases beyond retirement. These lengthy holding periods are tailored to our business model. Furthermore, payout of 50 percent of the annual bonus is delayed and subject to risk of forfeiture. The timing of the payout is determined by earnings performance.
- The use of perquisites at the company is very limited, and mainly composed of only two elements, financial planning for senior executives, and the use of club memberships for select executives which are largely tied to building business relationships.
- No tax assistance is provided by the company on any elements of executive officer compensation or perquisites other than relocation. The relocation program is broad-based and applies to all management, professional, technical and executive transferred employees.

Employee appraisal and ranking process

The assessment of individual performance is conducted through the company s employee appraisal program. Conducted annually, the appraisal process assesses performance against business performance measures and objectives relevant to each employee, including the means by which performance is achieved. These business performance measures include:

- total shareholder return;
- net income;
- return on capital employed;
- cash distribution to shareholders;
- safety, health, and environmental performance;
- operating performance of the Upstream, Downstream, and Chemical segments;
- business controls; and
- effectiveness of actions that support the long-term strategic direction of the company.

The ranking process, which is an integral part of the appraisal process, involves comparative assessment of employee performance using a standard process throughout the organization and at all levels. The appraisal process is integrated with the compensation program and also with the executive development process. Both have been in place for many years and are the basis for planning individual development and succession planning for management positions. The decision-making process with respect to compensation requires judgment, taking into account business and individual performance and responsibility. Quantitative targets or formulae are not used to assess individual performance or determine the amount of compensation.

Compensation program

Career orientation

The company s objective is to attract, develop and retain over a career the best talent available. It takes a long period of time and significant investment to develop the experienced executive talent necessary to succeed in the company s business; senior executives must have experience with all phases of the business cycle to be effective leaders. The company s compensation program elements reinforce the long-term approach. Career orientation among a dedicated and highly skilled workforce, combined with the highest performance standards, contributes to the company s leadership in the industry and serves the interests of shareholders in the long term. The company service of the named executive officers reflects this strategy. Their career service ranges from approximately 28 to over 30 years.

Consistent with the company s long-term career orientation, high-performing executives typically earn substantially higher levels of compensation in the final years of their careers than in the earlier years. This pay practice reinforces the importance of a long-term focus in making decisions that are key to business success.

The compensation program emphasizes individual experience and sustained performance, executives holding similar positions may receive substantially different levels of compensation.

The company s executive compensation program is composed of base salaries, cash bonuses and medium and long-term incentive compensation. The company **does not have written employment contracts** or any other agreement with its named executive officers providing for payments on change of control or termination of employment.

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Base salary

Salaries provide executives with a base level of income. The level of annual salary is based on the executive s responsibility, performance assessment and career experience. The salary program in 2009 maintained the company s competitive position on salaries in the marketplace. Individual salary increases vary depending on each executive s performance assessment and other factors such as time in position and potential for advancement. Salary decisions also directly affect the level of retirement benefits since salary is included in the retirement benefit calculation. Thus, the level of retirement benefits is also performance-based like other elements of compensation.

Annual bonus

Annual bonuses are typically granted to approximately 90 executives to reward their contributions to the business during the past year. Bonuses are drawn from an aggregate bonus pool established annually by the executive resources committee based on the company s financial and operating performance, and can be highly variable depending on annual financial and operating results.

In setting the size of the annual bonus pool and individual executive awards, the executive resources committee:

considers input from the chairman, president and chief executive officer on the performance of the company and from the company s internal compensation advisors regarding compensation trends as obtained from external consultants;
co