2025 annual financial statements and management discussion and analysis

Imperial

Cover photo:

Imperial's Strathcona Refinery, home to a renewable diesel facility that started production in July 2025. The project was first announced in 2021 and is expected to be the largest renewable diesel facility in Canada at full capacity.

Often called the world's most travelled refinery, the Strathcona Refinery was relocated from Whitehorse to the outskirts of Edmonton as Alberta's oil industry began following Imperial's 1947 oil discovery in Leduc. Today, approximately 30 percent of the petroleum products sold in western Canada originate from the Strathcona Refinery.

Annual financial statements and management's discussion and analysis of financial condition and operating results

For the year ended December 31, 2025

The following annual financial statements and management's discussion and analysis should be read in conjunction with the company's annual report on Form 10-K for the year ended December 31, 2025. Reference to "Item 1A. Risk factors" and specific page numbers in this document indicate the section and page numbers found in the company's annual report on Form 10-K. 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 are available online at www.sedarplus.ca, www.sec.gov and the company's website www.imperialoil.ca.

Unless the context otherwise indicates, reference to the "company" or "Imperial" includes Imperial Oil Limited and its subsidiaries, and reference to ExxonMobil includes Exxon Mobil Corporation and its affiliates, as appropriate.

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.

Forward-looking statements

Statements of future events or conditions in this report, including projections, targets, expectations, estimates, and business plans are forward-looking statements. Similarly, discussion of roadmaps or future plans related to carbon capture, transportation and storage, biofuel, hydrogen, and other future plans to reduce emissions and emission intensity of the company, its affiliates and third parties are dependent on future market factors, such as continued technological progress, policy support and timely rule-making and permitting, and represent forward-looking statements. Forward-looking statements can be identified by words such as believe, anticipate, intend, propose, plan, goal, seek, project, predict, target, estimate, expect, strategy, outlook, schedule, future, continue, likely, may, should, will and similar references to future periods. Forward-looking statements in this report include, but are not limited to, references to estimates, development, timing and recovery of reserves; the development drilling program at Cold Lake; Cold Lake experimental pilot operations to improve bitumen recovery; the evaluation and pace of the Aspen project; the timing, pace and results from the EBRT field pilot; the continued evaluation of other oil sands development projects; future activities with respect to Beaufort Sea licences; the company’s strategy for the energy transition and emission reduction goals; the company’s pursuit of lower-emission business opportunities and emission-reduction services and technologies; human capital resources strategy and impact; the company’s workforce transformation and restructuring plans to centralize activities in global capability centres, including timing and impacts; the cessation of production at Norman Wells, including impacts and timing; the measures required to comply with environmental regulations and any changes in such regulations; anticipated capital and operating expenditures, including with respect to environmental protection; the ability for autonomous operations at Kearl to continue capturing productivity improvements, reducing cost and enhancing safety; the effectiveness of the company's corporate governance and strategic planning practices, including with respect to risk management and oversight; the structure and effectiveness of the cybersecurity program; continued evaluation of the company’s share purchase program; being well-positioned to participate in substantial investments to develop Canadian energy supplies; the company’s long-term business outlook, including demand, supply and energy mix and transition pathways related to greenhouse gas emissions; the extent of ongoing effects of global events affecting supply and demand, including continued or renewed inflation, and the company’s ability to mitigate cost impacts in all price environments; the company’s Upstream business and investment strategies and evaluation of opportunities, including the company’s focus on operations integrity, innovative technologies, employee development, community investment, optimization within existing assets, cost reduction opportunities and productivity enhancements; the ability of the company’s current investment strategy of value and select volume growth to deliver robust returns and support long term growth; segment growth, competitive strategies and benefits from an integrated business model; the company’s Downstream strategies and their impacts on the company’s competitive position; Chemical competitive position and the benefits from integration with the Sarnia refinery and relationship with ExxonMobil; the impact of future funding of retirement plans; capital structure, liquidity sources and financial strength as a competitive advantage, for risk mitigation and meeting funding requirements; expected 2026 full year capital and exploration expenditures; earnings sensitivities and the impacts of changes in interest rates, crude oil prices, refining margins and foreign exchange rates; the company’s asset management program and potential divestments; risks associated with use of derivative instruments; the impact of any pending litigation, accounting standards and unrecognized tax benefits; standardized measures of discounted future cash flows; the effectiveness of the company’s ethics programs, restrictions on insider trading, related party transaction controls, diversity and shareholder engagement initiatives; and the effectiveness of the company’s director and executive compensation design and share ownership guidelines, including aligning with shareholder interests, managing risk, promoting long-term business performance, strategic objectives and shareholder value, and other stated objectives.

Forward-looking statements are based on the company’s current expectations, estimates, projections and assumptions at the time the statements are made. Actual future financial and operating results, including expectations and assumptions concerning future energy demand, supply and mix; production rates, growth and mix across various assets; production life, resource recoveries and reservoir performance; project plans, timing, costs, technical evaluations and capacities, and the company’s ability to effectively execute on these plans and operate its assets; the adoption and impact of new facilities or technologies on reductions to greenhouse gas emissions intensity, including but not limited to technologies using solvents to replace energy intensive steam at Cold Lake, the EBRT project, Strathcona renewable diesel, carbon capture and storage including in connection with hydrogen for the renewable diesel project, recovery technologies and efficiency projects, and any changes in the scope, terms, or costs of such projects; the degree and timeliness of support that will be provided by policymakers and other stakeholders for various new technologies such as carbon capture and storage; for renewable diesel, the availability and cost of locally-sourced and grown feedstock and the supply of renewable diesel to British Columbia in connection with its low-carbon fuel legislation; the amount and timing of emissions reductions, including the impact of lower carbon fuels; availability and performance of third-party service providers, including ExxonMobil global capability centres and other service providers located outside of Canada; receipt of regulatory and third-party approvals in a timely manner, especially with respect to large scale emissions reduction projects; applicable laws and government policies, including with respect to climate change, greenhouse gas emissions reductions and low carbon fuels; refinery utilization and product sales; the ability to offset any ongoing or renewed inflationary pressures; cash generation, financing sources and capital structure, such as dividends and shareholder returns, including the timing and amounts of share repurchases; capital and environmental expenditures; the capture of efficiencies within and between business lines and the ability to maintain near-term cost reductions as ongoing efficiencies; and commodity prices, foreign exchange rates and general market conditions, could differ materially depending on a number of factors.

These factors include global, regional or local changes in supply and demand for oil, natural gas, petroleum and petrochemical products, feedstocks and other market factors, economic conditions and seasonal fluctuations and resulting demand, price, differential and margin impacts, including Canadian and foreign government action with respect to supply levels, prices, trade tariffs, trade sanctions or trade controls, disruptions, realignment or breaking of trade alliances or agreements or a broader breakdown in global trade, and disruptions in military alliances or wars; political or regulatory events, including changes in law or government policy, applicable royalty rates, and tax laws; environmental regulation, including climate change and greenhouse gas regulation and changes to such regulation; environmental risks inherent in oil and gas activities; government policies supporting lower carbon investment opportunities; failure, delay, reduction, revocation or uncertainty regarding supportive policy and market development for the adoption of emerging lower-emission energy technologies and other technologies that support emissions reductions; the receipt, in a timely manner, of regulatory and third-party approvals, including for new technologies relating to the company’s lower emissions business activities; third-party opposition to company and service provider operations, projects and infrastructure; competition from alternative energy sources, other emission reduction technologies, and established competitors in such markets; availability and allocation of capital; availability and performance of third-party service providers, including ExxonMobil global capability centres and other service providers located outside of Canada; unanticipated technical or operational difficulties; effectiveness of company risk management programs and emergency response preparedness; project management and schedules and timely completion of projects; transportation for accessing markets; commercial negotiations; unexpected technological developments; the results of research programs and new technologies, including with respect to autonomous operations and greenhouse gas emissions, and the ability to bring new technologies to commercial scale on a commercially competitive basis; reservoir analysis and performance; the ability to develop or acquire additional reserves; operational hazards and risks; cybersecurity incidents including incidents caused by actors employing emerging technologies such as artificial intelligence; currency exchange rates; the occurrence, pace, rate of recovery and effects of public health crises, including the responses from governments; general economic conditions, including continued or renewed inflation and the occurrence and duration of economic recessions or downturns; and other factors discussed in "Item 1A Risk factors" and "Item 7 Management’s discussion and analysis of financial condition and results of operations" in this annual report on Form 10-K.

Forward-looking statements are not guarantees of future performance and involve a number of risks and uncertainties, some that are similar to other oil and gas companies and some that are unique to Imperial. Imperial’s actual results may differ materially from those expressed or implied by its forward-looking statements and readers are cautioned not to place undue reliance on them. Imperial undertakes no obligation to update any forward-looking statements contained herein, except as required by applicable law.

Forward-looking and other statements regarding Imperial's environmental, social and other sustainability efforts and aspirations are not an indication that these statements are material to investors or require disclosure in the company's filings with securities regulators. In addition, historical, current and forward-looking environmental, social and sustainability-related statements may be based on standards for measuring progress that are still developing, internal controls and processes that continue to evolve, and assumptions that are subject to change in the future, including future rule-making.

Energy demand models are forward-looking by nature and aim to replicate system dynamics of the global energy system, requiring simplifications. The reference to any scenario in this report, including any potential net-zero scenarios, does not imply Imperial views any particular scenario as likely to occur. In addition, energy demand scenarios require assumptions on a variety of parameters. As such, the outcome of any given scenario using an energy demand model comes with a high degree of uncertainty. Third-party scenarios discussed in this report reflect the modeling assumptions and outputs of their respective authors, not Imperial, and their use by Imperial is not an endorsement by the company of their underlying assumptions, likelihood or probability.

Investment decisions are made on the basis of Imperial's separate planning process. Any use of the modeling of a third-party organization within this report does not constitute or imply an endorsement by Imperial of any or all of the positions or activities of such organization.

Actions needed to advance the company's medium-term greenhouse gas emission-reductions plans are incorporated into its medium-term business plans, which are updated annually. The reference case for longer-term planning is based on ExxonMobil's Global Outlook (the Outlook) research and publication. The Outlook is reflective of the existing global policy environment and an assumption of increasing policy stringency and technology improvement to 2050. However, the Outlook does not attempt to project the degree of required future policy and technology advancement and deployment for the world to meet net zero by 2050. As future policies and technology advancements emerge, they will be incorporated into the Outlook, and the company's business plans will be updated accordingly. References to projects or opportunities may not reflect investment decisions made by the company. Individual projects or opportunities may advance based on a number of factors, including availability of stable and supportive policy, permitting, technological advancement for cost-effective abatement, insights from the company planning process, and alignment with partners and other stakeholders. Capital investment guidance in lower-emission investments is based on the company's corporate plan; however, actual investment levels will be subject to the availability of the opportunity set, public policy support, and focused on returns.

The term "project" as used in this report can refer to a variety of different activities and does not necessarily have the same meaning as in any government payment transparency reports.

Financial section

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Financial information (U.S. GAAP)

millions of Canadian dollars	**2025**	2024	2023
Revenues	**46,918**	51,359	50,702
Net income (loss):			
Upstream	**2,121**	3,262	2,512
Downstream	**1,869**	1,486	2,301
Chemical	**82**	171	164
Corporate and other	**(804)**	(129)	(88)
Net income (loss)	**3,268**	4,790	4,889
Cash and cash equivalents at year-end	**1,142**	979	864
Total assets at year-end	**42,309**	42,938	41,199
Long-term debt at year-end	**3,978**	3,992	4,011
Total debt at year-end	**3,997**	4,011	4,132
Other long-term obligations at year-end	**4,959**	3,870	3,851
Shareholders’ equity at year-end	**22,254**	23,473	22,222
Cash flow from operating activities	**6,708**	5,981	3,734
Per share information (Canadian dollars)			
Net income (loss) per common share - basic	**6.50**	9.05	8.51
Net income (loss) per common share - diluted	**6.48**	9.03	8.49
Dividends per common share - declared	**2.88**	2.40	1.94

Frequently used terms

Listed below are definitions of several of the company's key business and financial performance measures. The definitions are provided to facilitate understanding of the terms and how they are calculated. Certain measures included in this document are not prescribed by U.S. Generally Accepted Accounting Principles (GAAP). These measures constitute "non-GAAP financial measures" under Securities and Exchange Commission Regulation G and Item 10(e) of Regulation S-K, and "specified financial measures" under National Instrument 52-112 Non-GAAP and Other Financial Measures Disclosure of the Canadian Securities Administrators.

Reconciliation of these non-GAAP financial measures to the most comparable GAAP measure, and other information required by these regulations, have been provided. Non-GAAP financial measures and specified financial measures are not standardized financial measures under GAAP and do not have a standardized definition. As such, these measures may not be directly comparable to measures presented by other companies, and should not be considered a substitute for GAAP financial measures.

Capital employed

Capital employed is a non-GAAP financial measure that is a measurement of net investment. When viewed from the perspective of how capital is used by the business, it includes the company's property, plant and equipment and other assets, less liabilities, excluding both short-term and long-term debt. When viewed from the perspective of the sources of capital employed in total for the company, it includes total debt and equity. The most directly comparable financial measure that is disclosed in the financial statements is total assets within the company's Consolidated balance sheet. Both of these views include the company's share of amounts applicable to equity companies, which the company believes should be included to provide a more comprehensive measurement of capital employed.

Reconciliation of capital employed

millions of Canadian dollars		**2025**	2024	2023
From the Consolidated balance sheet				
Business uses: asset and liability perspective				
Total assets		**42,309**	42,938	41,199
Less:	Total current liabilities excluding notes and loans payable	**(6,597)**	(6,988)	(6,482)
	Total long-term liabilities excluding long-term debt	**(9,461)**	(8,466)	(8,363)
Add:	Imperial's share of equity company debt	**13**	25	21
Total capital employed		**26,264**	27,509	26,375
Total company sources: debt and equity perspective				
Notes and loans payable		**19**	19	121
Long-term debt		**3,978**	3,992	4,011
Shareholders' equity		**22,254**	23,473	22,222
Add:	Imperial's share of equity company debt	**13**	25	21
Total capital employed		**26,264**	27,509	26,375

Return on average capital employed (ROCE)

ROCE is a non-GAAP ratio. The company's total ROCE is net income excluding the after-tax cost of financing divided by total average capital employed (an average of the beginning and end-of-year amounts). Net income includes Imperial's share of net income of equity companies, consistent with the definition used for capital employed, and excludes the cost of financing. Capital employed is a non-GAAP financial measure and is disclosed and reconciled above. The company has consistently applied its ROCE definition for many years and views it as one of the best measures of historical capital productivity in a capital-intensive, long-term industry. Additional measures, which are more cash flow based, are used to make investment decisions.

Components of return on average capital employed

millions of Canadian dollars	**2025**	2024	2023
From the Consolidated statement of income			
Net income (loss)	**3,268**	4,790	4,889
Financing (after-tax) including Imperial's share of equity companies	**30**	43	66
Net income (loss) excluding financing	**3,298**	4,833	4,955
Average capital employed	**26,887**	26,942	26,484
Return on average capital employed (percent) – corporate total	**12.3**	17.9	18.7

Cash flows from (used in) operating activities and asset sales

Cash flows from operating activities and asset sales is a non-GAAP financial measure that is the sum of the net cash provided by operating activities and proceeds from asset sales reported in the Consolidated statement of cash flows. This cash flow reflects the total sources of cash both from operating the company's assets and from the divesting of assets. The most directly comparable financial measure that is disclosed in the financial statements is cash flows from (used in) operating activities within the company's Consolidated statement of cash flows. The company employs a long-standing and regular disciplined review process to ensure that assets are contributing to the company's strategic objectives. Assets are divested when they no longer meet these objectives or are worth considerably more to others. Because of the regular nature of this activity, the company believes it is useful for investors to consider sales proceeds together with cash provided by operating activities when evaluating cash available for investment in the business and financing activities, including shareholder distributions.

Reconciliation of cash flows from (used in) operating activities and asset sales

millions of Canadian dollars	**2025**	2024	2023
From the Consolidated statement of cash flows			
Cash flows from (used in) operating activities	**6,708**	5,981	3,734
Proceeds from asset sales	**101**	25	86
Total cash flows from (used in) operating activities and asset sales	**6,809**	6,006	3,820

Operating costs

Operating costs is a non-GAAP financial measure that is the costs during the period to produce, manufacture, and otherwise prepare the company's products for sale – including energy costs, staffing and maintenance costs. It excludes the cost of raw materials, taxes and interest expense and is presented on a before-tax basis. The most directly comparable financial measure that is disclosed in the financial statements is total expenses within the company's Consolidated statement of income. While the company is responsible for all revenue and expense elements of net income, operating costs represent the expenses most directly under the company's control and therefore, are useful in evaluating the company's performance.

Reconciliation of operating costs

millions of Canadian dollars	**2025**	2024	2023
From the Consolidated statement of income			
Total expenses	**42,816**	45,293	44,600
Less:			
Purchases of crude oil and products	**29,807**	33,184	32,399
Federal excise tax and fuel charge	**1,715**	2,535	2,402
Financing	**12**	41	69
Subtotal	**31,534**	35,760	34,870
Imperial's share of equity company expenses	**67**	80	76
Total operating costs	**11,349**	9,613	9,806

Components of operating costs

millions of Canadian dollars	**2025**	2024	2023
From the Consolidated statement of income			
Production and manufacturing	**7,269**	6,599	6,879
Selling and general	**1,386**	945	857
Depreciation and depletion	**2,579**	1,983	1,907
Non-service pension and postretirement benefit	**41**	3	82
Exploration	**7**	3	5
Subtotal	**11,282**	9,533	9,730
Imperial's share of equity company expenses	**67**	80	76
Total operating costs	**11,349**	9,613	9,806

Net income (loss) excluding identified items

Net income (loss) excluding identified items is a non-GAAP financial measure that is total net income (loss) excluding individually significant non-operational events with an absolute corporate total earnings impact of at least $100 million in a given quarter. The net income (loss) impact of an identified item for an individual segment may be less than $100 million when the item impacts several segments or several periods. The most directly comparable financial measure that is disclosed in the financial statements is "Net income (loss)" within the company's Consolidated statement of income. Management uses these figures to improve comparability of the underlying business across multiple periods by isolating and removing significant non-operational events from business results. The company believes this view provides investors increased transparency into business results and trends, and provides investors with a view of the business as seen through the eyes of management. Net income (loss) excluding identified items is not meant to be viewed in isolation or as a substitute for net income (loss) as prepared in accordance with U.S. GAAP. All identified items are presented on an after-tax basis.

Reconciliation of net income (loss) excluding identified items

millions of Canadian dollars	**2025**	2024	2023
From the Consolidated statement of income			
Net income (loss) (U.S. GAAP)	**3,268**	4,790	4,889
Less identified items included in Net income (loss)			
Impairments	**(570)**	—	—
Restructuring charges	**(249)**	—	—
Other (a)	**(212)**	—	—
Subtotal of identified items	**(1,031)**	—	—
Net income (loss) excluding identified items	**4,299**	4,790	4,889

(a) Contractual obligations associated with the Norman Wells end of field life acceleration.

Management’s discussion and analysis of financial condition and results of operations

Overview

The following discussion and analysis of the company’s financial results, as well as the accompanying financial statements and related notes to consolidated financial statements to which they refer, are the responsibility of the management of Imperial Oil Limited.

The company’s accounting and financial reporting fairly reflect its integrated business model involving exploration for, and production of, crude oil and natural gas; manufacture, trade, transport and sale of crude oil, natural gas, petroleum products, petrochemicals and a variety of specialty products; and pursuit of lower-emission business opportunities including carbon capture and storage, hydrogen, lower-emission fuels, and lithium.

Imperial, with its resource base, financial strength, disciplined investment approach and technology portfolio, is well-positioned to participate in substantial investments to develop new Canadian energy supplies. The company’s reportable segments are Upstream, Downstream, and Chemicals. The company’s integrated business model generally reduces the company’s risk from changes in commodity prices. While commodity prices depend on supply and demand and may be volatile on a short-term basis, the company’s investment decisions are grounded on fundamentals reflected in its long-term business outlook, and use a disciplined approach in selecting and pursuing the most attractive investment opportunities. The annual company plan process establishes the economic assumptions used for evaluating investments and sets operating and capital objectives. ExxonMobil's *Global Outlook* (the Outlook), developed annually, is the foundation for the plan assumptions. Price ranges for crude oil, including price differentials, refinery and chemical margins, volumes, operating costs including greenhouse gas emissions pricing, and foreign currency exchange rates are part of the company plan assumptions developed annually. Company plan volume projections are based on individual field production profiles, which are also updated at least annually. Major investment opportunities are evaluated over a range of potential market conditions. All major investments are reappraised to ensure the company learns from its investment decisions, and the development and execution of the project. Lessons learned are incorporated into future projects.

The term "project" as used in this report can refer to a variety of different activities and does not necessarily have the same meaning as in any government payment transparency reports.

Business environment

Long-term business outlook

The "Long-term business outlook" is based on Exxon Mobil Corporation's *Global Outlook* (the Outlook), which combined with the near-term pathways, is used to help inform the company's long-term business strategies and investment plans.

The company's business planning is underpinned by a deep understanding of long-term market fundamentals. These fundamentals include supply and demand trends; the scale and variety of energy needs worldwide; capability, practicality and affordability of energy alternatives, including lower-carbon solutions; greenhouse gas emission-reduction technologies; and relevant government policies. The Outlook considers these fundamentals to form the basis for the company's long-term business planning, investment decisions, and research programs. The Outlook reflects the company's view of global energy demand and supply through 2050. It is a projection based on current trends in technology, government policies, consumer preferences, geopolitics, and economic development.

The Outlook uses projections and scenarios from reputable third parties such as the International Energy Agency (IEA) and the Intergovernmental Panel on Climate Change (IPCC). Included in the range of these scenarios are: the IPCC Likely Below 2°C scenarios and three scenarios from the IEA; IEA Stated Policies Scenario (STEPS; 2025 World Energy Outlook (WEO)), which reflects a sector-by-sector assessment of current policy in place and those announced by governments; IEA Announced Pledges Scenario (APS; 2024 WEO), which reflects aspirational government targets met on time and in full; and IEA Net Zero Emissions by 2050 Scenario (NZE; 2025 WEO), which the IEA describes as highly ambitious and challenging, acknowledging that society is not currently on the IEA NZE pathway. No single transition pathway can be reasonably predicted, given the wide range of uncertainties. Key unknowns include yet-to-be-developed or changes in developed government policies, market conditions, and advances in technology that may influence the cost, pace, and potential availability of certain pathways. Scenarios that employ a full complement of technology options are likely to provide the most economically efficient pathways.

Using the company's own experts and third-party sources, the company monitors a variety of signposts that may indicate a potential shift in the energy transition. For example, the regional pace of the transition could be influenced by the cost of new technologies compared to existing or alternative energy sources.

By 2050, the world's population is projected to be around 9.7 billion people, or nearly 2 billion more than in 2024. Coincident with this population increase, the Outlook projects worldwide economic growth to average approximately 2.5 percent per year, with economic output nearly doubling by 2050 compared to 2024. As economies and populations grow, and as living standards improve for billions of people, the need for energy is expected to continue to rise. Even with significant efficiency gains, global energy demand is projected to rise by over 10 percent from 2024 to 2050. This increase in energy demand is expected to be driven by developing countries (i.e., those that are not member nations of the Organization for Economic Co-operation and Development (OECD)). By contrast, energy use in developed nations is expected to decline by more than 10 percent as efficiency improves.

As expanding prosperity drives global energy demand higher, increasing use of energy-efficient technologies and practices, as well as lower-emission products, will continue to help significantly reduce energy consumption and CO_2 emissions per unit of economic output over time. Substantial efficiency gains are likely in all key aspects of the world's economy through 2050, affecting energy requirements for power generation, transportation, industrial applications, and residential and commercial needs.

Under the Outlook, global electricity demand is expected to increase more than 70 percent from 2024 to 2050, with developing countries likely to account for approximately 80 percent of the increase. Consistent with this projection, power generation is expected to remain the largest and fastest growing major segment of global primary energy demand, supported by a wide variety of energy sources. The share of coal-fired generation is expected to decline substantially to approximately 15 percent of the world's electricity in 2050, versus approximately 35 percent in 2024, in part due to policies to improve air quality as well as reduce greenhouse gas emissions to address risks related to climate change. From 2024 to 2050, the amount of electricity supplied using natural gas, nuclear power, and renewables is expected to more than double, accounting for the entire growth in electricity supplies and offsetting the reduction of coal. Electricity from wind and solar is expected to increase nearly 400 percent, helping total renewables (including other sources, e.g., hydropower) to account for approximately 90 percent of the increase in electricity supplies through 2050. Total renewables are expected to reach over 50 percent of global electricity supplies by 2050. Natural gas and nuclear are expected to be about 20 percent and 10 percent, respectively, of global electricity supplies by 2050. Supplies of electricity by energy type will reflect significant differences across regions reflecting a wide range of factors, including the cost and availability of various energy supplies and policy developments.

Energy for transportation - including cars, trucks, ships, trains, and airplanes - is expected to increase by nearly 25 percent from 2024 to 2050. Transportation energy demand is expected to account for over 50 percent of the growth in liquid fuels demand worldwide over this period. Light-duty vehicle demand for liquid fuels is projected to have peaked this decade, and then decline to levels seen in the early-2010s by 2050, as the impact of better fuel economy and significant growth in electric cars, led by China, Europe, and the United States, work to offset growth in the worldwide car fleet of approximately 60 percent. By 2050, light-duty vehicles are expected to account for around 20 percent of global liquid fuels demand. During the same time period, nearly all the world's commercial transportation fleets are expected to continue to run on liquid fuels, including biofuels, which are expected to be widely available and offer practical advantages in providing a large quantity of energy in small volumes.

Almost half of the world's energy use is dedicated to industrial activity. As the global middle class continues to grow, demand for durable products, appliances, and consumable goods will increase. Industry uses energy products both as a fuel and as a feedstock for chemicals, asphalt, lubricants, waxes, and other specialty products. The Outlook anticipates technology advances, as well as the increasing shift toward cleaner forms of energy, such as electricity and natural gas, with coal declining. Demand for oil will continue to grow as a feedstock for industry.

As populations grow and prosperity rises, more energy will be needed to power homes, offices, schools, shopping centers, hospitals, etc. Combined residential and commercial energy demand is projected to rise by around 15 percent through 2050. Led by the growing economies of developing nations, average worldwide household electricity use is expected to rise more than 60 percent between 2024 and 2050.

Liquid fuels provide the largest share of global energy supplies today reflecting broad-based availability, affordability, ease of transportation, and fitness as a practical solution to meet a wide variety of needs. By 2050, global demand for liquid fuels is projected to grow to nearly 115 million oil-equivalent barrels per day, an increase of about 10 percent from 2024. The non-OECD share of global liquid fuels demand is expected to increase to about 70 percent by 2050, as liquid fuels demand in the OECD is expected to decline by more than 25 percent. Much of the global liquid fuels demand today is met by crude production from conventional sources; these supplies will remain important, and significant development activity is expected to offset much of the natural declines from these fields. At the same time, a variety of supply sources - including tight oil, deepwater, oil sands, natural gas liquids, and biofuels - are expected to grow to help meet rising demand. Timely investments will remain critical to meeting global needs with reliable and affordable supplies.

Natural gas is a lower-emission, versatile and practical fuel for a wide variety of applications. Global natural gas demand is expected to rise nearly 20 percent from 2024 to 2050, with approximately 70 percent of that increase coming from the Asia Pacific region. Significant growth in supplies of unconventional gas - the natural gas found in shale and other tight rock formations - will help meet these needs. In total, over 40 percent of the growth in natural gas supplies is expected to come from unconventional sources. At the same time, conventionally-produced natural gas is likely to remain the cornerstone of global supply, meeting around two-thirds of worldwide demand in 2050. Liquefied natural gas (LNG) trade will expand significantly, meeting about 75 percent of the increase in global demand growth, with much of this supply expected to help meet rising demand in the Asia Pacific region.

The world's energy mix is highly diverse and will remain so through 2050. Oil is expected to continue as the largest source of energy with its share remaining close to 30 percent in 2050. Coal and natural gas are the next largest sources of energy today, with the share of natural gas growing to more than 25 percent by 2050, while the share of coal falls to about half that of natural gas. Nuclear power is projected to grow, as many nations are likely to expand nuclear capacity to address rising electricity needs as well as energy security and environmental issues. Total renewable energy is expected to exceed 20 percent of global energy by 2050, with other renewables (e.g., biomass, hydropower, geothermal) contributing a combined share of more than 10 percent. Total energy supplied from wind and solar is expected to increase rapidly, growing nearly 350 percent from 2024 to 2050, when they are projected to be greater than 10 percent of the world energy mix.

Decarbonization of industrial activities will require a suite of lower-carbon technologies supported by stable policies. Lower-emission fuels, hydrogen-based fuels, and carbon capture and storage are three key lower-carbon solutions needed to support a lower-emission future, in addition to wind and solar. Along with electrification, lower-emission fuels are expected to play an important role in decarbonization of the transportation sector, particularly in hard-to-decarbonize areas, such as aviation. Low-carbon hydrogen will be a key enabler replacing traditional furnace fuel to decarbonize the industrial sector. Hydrogen and hydrogen-based fuels like ammonia are also expected to make inroads into commercial transportation as technology improves to lower its cost and policy develops to support the needed infrastructure development. Carbon capture and storage on its own, or in combination with hydrogen production, is among the few proven technologies that could enable CO_2 emission reductions from high-emitting and hard-to-decarbonize sectors such as power generation and heavy industries, including manufacturing, refining, and petrochemicals.

The Outlook projects that oil demand will remain above 100 million barrels per day to 2050. And even under the average of IPCC Likely Below 2°C scenarios, oil demand still comes to 65 million barrels per day in 2050 – about two thirds of current consumption.

The Outlook shows oil production declines at a rate of about 15 percent per year. At that rate, in the absence of continued investment, by 2030 oil supplies would fall from 100 million barrels per day to less than 30 million barrels, more than 70 million barrels per day short of what is needed to meet demand. Limiting investment to only existing fields would slow the decline to about 4 percent, however, this would still be well below the oil demand in the average of IPCC Likely Below 2°C scenarios.

To meet projected demand, the company anticipates that the world's available oil and gas resource base will grow, not only from new discoveries, but also from increases in previously discovered fields. Technology will underpin these increases. The investments to develop and supply resources to meet global demand through 2050 will be significant and would be needed to meet even rapidly declining demand for oil and gas envisioned in aggressive decarbonization scenarios.

International accords and underlying regional and national regulations covering greenhouse gas emissions continue to evolve with uncertain timing and outcome, making it difficult to predict their business impact. The company's estimates of potential costs related to greenhouse gas emissions align with applicable provincial and federal regulations. Additionally, the company uses the Outlook as a foundation for estimating energy supply and demand requirements from various energy sources and uses, and the Outlook takes into account policies established to reduce energy related greenhouse gas emissions. The climate accord reached at the 2015 Conference of the Parties (COP 21) in Paris set many new goals, and many related policies are still emerging. The Outlook reflects an environment with increasingly stringent climate policies and seeks to identify potential impacts of these climate related government policies, which often target specific sectors. For purposes of the Outlook, a proxy cost on energy-related CO_2 emissions is assumed, based on regional considerations and relative levels of economic development, and by 2050, reaches up to $150 USD per metric ton for OECD nations and up to $100 USD per metric ton for non-OECD nations. As people and nations look for ways to reduce risks of global climate change, they will continue to need practical solutions that do not jeopardize the affordability or reliability of the energy they need. The company continues to monitor the updates to the Nationally Determined Contributions (NDCs) that are submitted by nations that are signatories to the Paris Agreement, as well as other policy developments in light of net-zero ambitions formulated by some nations, including Canada.

The information provided in the Outlook includes ExxonMobil's internal estimates and projections based upon internal data and analyses, as well as publicly available information from external sources including the International Energy Agency.

Progress reducing emissions
Practical solutions to the world's energy and climate challenges will benefit from market competition in addition to well-informed, well-designed and transparent policy approaches that carefully weigh costs and benefits. Such policies are likely to help manage the risks of climate change while also enabling societies to pursue other high priority goals around the world – including clean air and water, access to reliable and affordable energy, and economic progress for all people. The company encourages sound policy solutions that reduce climate-related risks across the economy at the lowest societal cost. All practical and economically viable energy sources will need to be pursued to continue meeting global energy demand, recognizing the scale and variety of worldwide energy needs, as well as the importance of expanding access to modern energy to promote better standards of living for billions of people.

As part of the company's efforts to provide solutions that lower the greenhouse gas emissions intensity of its operations and provide lower life-cycle emissions products to customers, the company will continue to evaluate and deploy technologies such as oil sands technologies that use less steam, carbon capture and storage, energy efficiency projects, and low-emissions fuels. Decisions to deploy these technologies will be informed by market conditions and government policies.

Recent business environment

During 2025, the price of crude oil decreased relative to 2024, as increased OPEC+ output, record U.S. production, and global economic growth deceleration created a significant supply-demand imbalance, while brief geopolitical price spikes faded quickly and failed to counter the broader downward pressure. In addition, the Canadian WTI/WCS spread narrowed as expanded TMX export capacity improved market access, while steady U.S. refinery demand and reduced western Canadian inventories in the second quarter, driven by turnarounds and wildfire-related supply impacts, further tightened the differential. Industry refining margins improved in 2025, influenced by geopolitical factors and supply disruptions. The company closely monitors market trends and works to mitigate both operating and capital cost impacts in all price environments.

During 2025, the United States announced a variety of trade-related actions, including the imposition of tariffs on imports from Canada and several other countries. In response, Canada announced its own retaliatory tariffs. Despite the current uncertainty as to what effects these actions will ultimately have on Imperial, its suppliers and its customers, the company does not anticipate any material near-term financial impacts.

Business results

Consolidated

millions of Canadian dollars	**2025**	2024	2023
Net income (loss) (U.S. GAAP)	**3,268**	4,790	4,889
Identified items[1] included in Net income (loss)			
Impairments	**(570)**	—	—
Restructuring charges	**(249)**	—	—
Other (a)	**(212)**	—	—
Subtotal of identified items[1]	**(1,031)**	—	—
Net income (loss) excluding identified items[1]	**4,299**	4,790	4,889

(a) Contractual obligations associated with the Norman Wells end of field life acceleration.

2025
Net income in 2025 was $3,268 million, or $6.48 per share on a diluted basis, compared to $4,790 million, or $9.03 per share in 2024. Current year results include identified items[1] of: $320 million after-tax ($421 million before-tax) related to the Norman Wells end of field life acceleration; a $306 million after-tax ($406 million before-tax) non-cash impairment charge of the Calgary Imperial Campus; a $249 million after-tax ($330 million before-tax) restructuring charge; and a one-time $156 million after-tax ($206 million before-tax) charge associated with the optimization of materials and supplies inventory.

2024
Net income in 2024 was $4,790 million, or $9.03 per share on a diluted basis, compared to $4,889 million, or $8.49 per share in 2023.

[1] Non-GAAP financial measure - see "Frequently used terms" section for definition and reconciliation.

Upstream

Overview

The company produces crude oil and natural gas for sale predominantly into North American markets. The company’s Upstream business strategies guide the company’s exploration, development, production, research and gas marketing activities. These strategies include improving asset reliability, accelerating development and application of high impact technologies, maximizing value by capturing new business opportunities and managing the existing portfolio, as well as pursuing sustainable improvements in organizational efficiency and effectiveness. These strategies are underpinned by a relentless focus on operations integrity, commitment to innovative technologies, disciplined approach to investing and cost management, development of employees and investment in the communities within which the company operates.

The company has a significant oil and gas resource base and a large inventory of potential projects. The company’s current investment strategy is to invest for value and select volume growth, with focus on optimization within existing assets, cost reduction opportunities and productivity enhancements that aim to deliver robust returns at a wide range of prices. The company also continues to evaluate opportunities to support long-term growth. Although actual volumes typically vary from year to year, the focus is on value-add, long-term growth opportunities within the context of the factors described in "Item 1A. Risk factors". The company continually evaluates opportunities, including the pace of development for the Aspen project.

Prices for most of the company's crude oil sold are referenced to Western Canada Select (WCS) and West Texas Intermediate (WTI) oil markets. Additionally, the market price for WCS is typically lower than light and medium grades of oil, and price differentials between WCS and WTI can fluctuate.

The company believes prices over the long term will be driven by market supply and demand, with the demand side largely being a function of general economic activity, alternative energy sources, levels of prosperity, technology advancements, consumer preference and government policies. On the supply side, prices may be significantly impacted by political events, logistics constraints, the actions of OPEC or OPEC+, governments, alternative energy sources, and other factors. To manage the risks associated with price, the company tests the resiliency of its annual plans and all major investments across a range of price scenarios.

Key events

Upstream assets demonstrated strong operational performance in 2025. The company continued to benefit from its actions implemented in prior years to manage the cost structure and improve the reliability of its assets, enabling the Upstream to capture significant value.

Upstream full-year production averaged 438,000 gross oil-equivalent barrels per day.

At Kearl, gross production was about 280,000 barrels per day (199,000 barrels Imperial’s share), which is a decrease of about 1,000 barrels per day (1,000 barrels Imperial's share) compared to 2024.

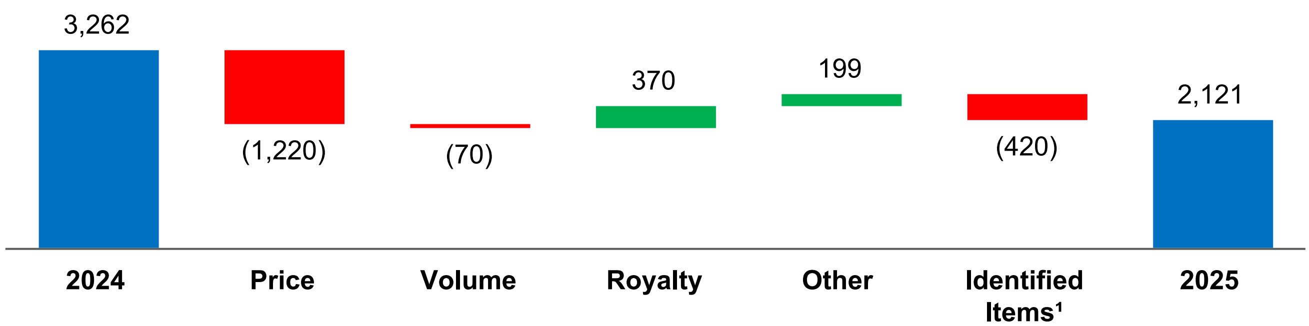
At Cold Lake, annual production averaged 151,000 barrels per day, which is an increase of about 3,000 barrels per day compared to 2024.

At Syncrude, annual production averaged 79,000 barrels per day, which is an increase of about 4,000 barrels per day compared to 2024.

As described in more detail in "Item 1A. Risk factors", environmental risks and climate related regulations could have negative impacts on the upstream business.

Results of operations

2025 Net income (loss) factor analysis
millions of Canadian dollars



Price – Average bitumen realizations decreased by $7.52 per barrel, primarily driven by lower marker prices partially offset by narrowing WTI/WCS spread and favourable diluent. Synthetic crude oil realizations decreased by $12.92 per barrel, primarily driven by lower WTI.

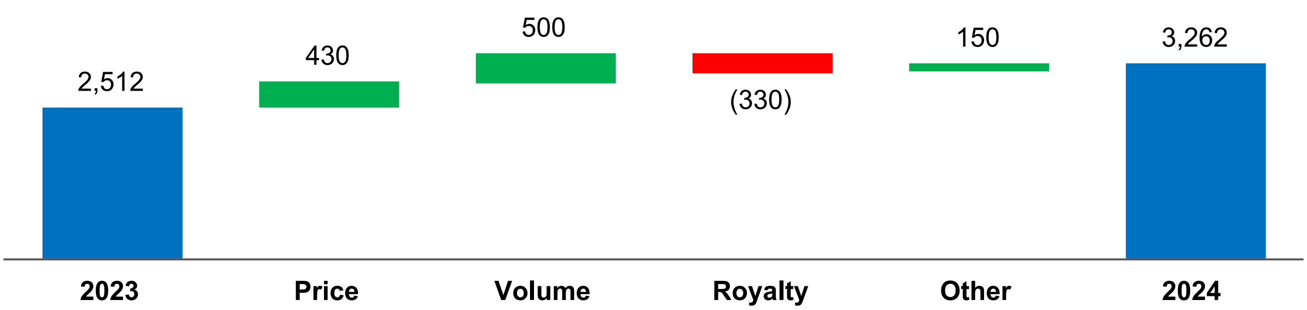
Volume – Inventory impacts partially offset by higher production.

Royalty – Lower royalties were primarily driven by lower commodity prices.

Other – Primarily due to favourable foreign exchange impacts of about $190 million.

Identified items[1] – $320 million after-tax ($421 million before-tax) related to the Norman Wells end of field life acceleration and a separate one-time $100 million after-tax ($131 million before-tax) charge associated with the Upstream portion of the optimization of materials and supplies inventory.

2024 Net income (loss) factor analysis
millions of Canadian dollars



Price – Average bitumen realizations increased by $7.11 per barrel, primarily driven by the narrowing WTI/WCS spread and lower diluent costs, partially offset by lower marker prices. Synthetic crude oil realizations decreased by $3.66 per barrel, primarily driven by a weaker Synthetic/WTI spread and lower WTI.

Volume – Higher volumes were primarily driven by Grand Rapids production at Cold Lake, as well as improved mine fleet productivity and optimized turnaround at Kearl.

Royalty – Higher royalties were primarily driven by higher volumes and prices.

Other – Primarily due to lower operating expenses of about $210 million, mainly driven by lower energy prices, and favourable foreign exchange impacts of about $120 million, partially offset by lower electricity sales at Cold Lake due to lower prices.

[1] Non-GAAP financial measure - see "Frequently used terms" section for definition and reconciliation.

Marker prices and average realizations

Canadian dollars, unless otherwise noted	**2025**	2024	2023
West Texas Intermediate (US$ per barrel)	**64.73**	75.78	77.60
Western Canada Select (US$ per barrel)	**53.76**	61.04	58.97
WTI/WCS Spread (US$ per barrel)	**10.97**	14.74	18.63
Bitumen (per barrel)	**67.01**	74.53	67.42
Synthetic crude oil (per barrel)	**88.99**	101.91	105.57
Conventional crude oil (per barrel)	**33.10**	55.63	59.30
Natural gas (per thousand cubic feet)	**1.76**	0.69	2.58
Average foreign exchange rate (US$)	**0.72**	0.73	0.74

Crude oil - production and sales (a)

thousands of barrels per day	**2025**		2024		2023	
	gross	**net**	gross	net	gross	net
Bitumen	**350**	**310**	348	299	326	283
Synthetic crude oil (b)	**79**	**68**	75	62	76	67
Conventional crude oil	**4**	**4**	5	5	5	5
Total crude oil production	**433**	**382**	428	366	407	355
Bitumen sales, including diluent (c)	**475**		471		442	

Natural gas - production and production available for sale (a)

millions of cubic feet per day	**2025**		2024		2023	
	gross	**net**	gross	net	gross	net
Production (d) (e)	**29**	**29**	30	30	33	32
Production available for sale (f)		**8**		9		11

(a) Volume per day metrics are calculated by dividing the volume for the period by the number of calendar days in the period. Gross production is the company’s share of production (excluding purchases) before deduction of the mineral owners’ or governments’ share or both.
(b) The company’s synthetic crude oil production volumes were from the company’s share of production volumes in the Syncrude joint venture and include immaterial amounts of bitumen and other products exported to the operator's facilities using an existing interconnect pipeline.
(c) Diluent is natural gas condensate or other light hydrocarbons added to crude bitumen to facilitate transportation.
(d) Gross production of natural gas includes amounts used for internal consumption with the exception of the amounts reinjected.
(e) Net production is gross production less the mineral owners’ or governments’ share or both. Net production reported in the above table is consistent with production quantities in the net proved reserves disclosure.
(f) Includes sales of the company’s share of net production and excludes amounts used for internal consumption.

2024
Higher bitumen production was mainly attributable to Grands Rapids production at Cold Lake, as well as improved mine fleet productivity and optimized turnaround at Kearl.

Downstream

Overview

The company's Downstream serves predominantly Canadian markets with refining, trading, logistics and marketing activities. The company's Downstream business strategies competitively position the company across a range of market conditions. These strategies include targeting industry-leading performance in reliability, safety and operations integrity, as well as maximizing value from advanced technologies, capitalizing on integration across the company's businesses, selectively investing for resilient and advantaged returns, operating efficiently and effectively, and providing quality, valued and differentiated products and services to customers.

The company owns and operates three refineries in Canada with aggregate distillation capacity of 434,000 barrels per day. Refining margins are largely driven by differences in commodity prices and are a function of the difference between what a refinery pays for its raw materials (primarily crude oil) and the market prices for the range of products produced (primarily gasoline, heating oil, diesel oil, jet fuel, fuel oil and asphalt). Crude oil and many products are widely traded with published prices, including those quoted on the New York Mercantile Exchange. Prices for these commodities are determined by the global and regional marketplaces and are influenced by many factors, including global and regional supply/demand balances, inventory levels, industry refinery operations, import/export balances, currency fluctuations, seasonal demand, weather and geopolitical considerations. While industry refining margins significantly impact earnings, strong operational performance, product mix optimization, and disciplined cost control are also critical to the company's strong financial performance. The company's integration across the value chain, from refining to marketing, enhances overall value across the fuels business.

Key events

Refining margins strengthened in 2025 driven by strong distillate demand and relatively low inventory levels due to global supply disruptions. The company continues to closely monitor industry and global economic conditions.

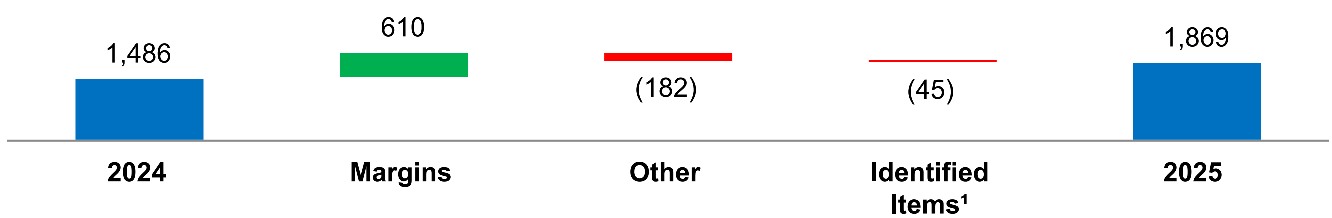
In January 2023, the company fully funded the Strathcona renewable diesel project, the largest such facility in Canada, located at Strathcona refinery. The facility uses hydrogen, locally sourced and grown feedstocks and the company's proprietary catalyst to produce renewable diesel. Facility construction commenced in 2023 and was completed and commissioned with first on-spec renewable diesel produced in July 2025 bringing lower-emission fuels to market.

As described in more detail in "Item 1A. Risk factors", proposed carbon policy and other climate related regulations, as well as continued biofuels mandates, could have negative impacts on the Downstream business.

The company supplies petroleum products through Esso and Mobil-branded sites and independent marketers. At the end of 2025, there were about 2,600 sites operating under a branded wholesaler model, in alignment with Esso and Mobil brand standards, whereby the company supplies fuel to independent third parties.

Results of operations

2025 Net income (loss) factor analysis
millions of Canadian dollars



Margins – Higher margins primarily reflect improved market conditions.

Other – Primarily due to higher operating expenses of about $140 million driven by higher energy costs, additional maintenance in the company's eastern manufacturing hub of about $70 million, and unfavourable wholesale volume impacts of about $60 million, partially offset by lower turnaround impacts of about $100 million.

[1] Non-GAAP financial measure - see "Frequently used terms" section for definition and reconciliation.

2024 Net income (loss) factor analysis
millions of Canadian dollars

Margins – Lower margins primarily reflect weaker market conditions.

Other – Primarily due to lower turnaround impacts of about $120 million and favourable foreign exchange impacts of about $110 million, partially offset by lower volumes of about $60 million.

Refinery utilization

thousands of barrels per day (a)	**2025**	2024	2023
Total refinery throughput (b)	**402**	399	407
Rated capacity at December 31 (c)	**434**	434	433
Utilization of total refinery capacity (percent)	**93**	92	94

(a) Volume per day metrics are calculated by dividing the volume for the period by the number of calendar days in the period.
(b) Refinery throughput is the volume of crude oil and feedstocks that is processed in the refinery atmospheric distillation units.
(c) Refining capacity data is based on 100 percent of rated refinery process unit stream-day capacities to process inputs to atmospheric distillation units under normal operating conditions, less the impact of shutdowns for regular repair and maintenance activities, averaged over an extended period of time.

2024
Lower refinery throughput in 2024 reflected the impact of planned turnaround activities at Nanticoke, Sarnia and Strathcona refineries.

Petroleum product sales

thousands of barrels per day (a)	**2025**	2024	2023
Gasolines	**224**	223	228
Heating, diesel and jet fuels	**177**	175	176
Lube oils and other products (b)	**48**	46	43
Heavy fuel oils	**21**	22	24
Net petroleum product sales	**470**	466	471

(a) Volume per day metrics are calculated by dividing the volume for the period by the number of calendar days in the period.
(b) In 2025 and 2024, benzene and aromatic solvent sales are reported under Petroleum product sales - Lube oils and other products, whereas in 2023, they were reported under Petrochemical sales. The company has determined that the impact of this change is not material; therefore, the comparative periods have not been recast.

Chemical

Overview

North America continued to benefit from abundant supplies of natural gas and gas liquids, providing both low cost energy and feedstock for steam crackers.

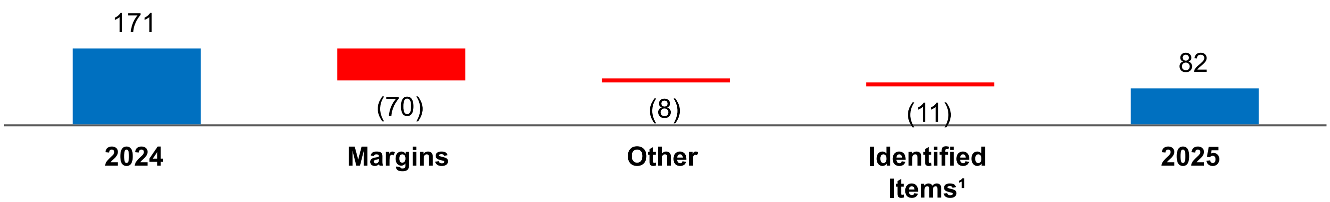
Key events

In 2025, the Chemicals business had strong operating performance, building on the improvements achieved following the completion of maintenance activities in prior years.

The company maintains a competitive advantage through continued operational excellence, consistent product quality, investment and cost discipline, and integration of its chemical plant in Sarnia with the refinery. The company also benefits from its relationship with ExxonMobil's North American chemical businesses, enabling Imperial to maintain a leadership position in its key market segments.

Results of operations

2025 Net income (loss) factor analysis
millions of Canadian dollars



Margins – Lower margins primarily reflect weaker industry polyethylene margins.

2024 Net income (loss) factor analysis
millions of Canadian dollars

Sales

thousands of tonnes	**2025**	2024	2023
Total petrochemical sales (a)	**683**	684	820

(a) In 2025 and 2024, benzene and aromatic solvent sales are reported under Petroleum product sales - Lube oils and other products, whereas in 2023, they were reported under Petrochemical sales. The company has determined that the impact of this change is not material; therefore, the comparative periods have not been recast.

Corporate and other

millions of Canadian dollars	**2025**	2024	2023
Net income (loss)	**(804)**	(129)	(88)

Current year results include identified items[1] of a $306 million after-tax ($406 million before-tax) non-cash impairment charge of the Calgary Imperial Campus and a $249 million after-tax ($330 million before-tax) restructuring charge; results also reflect higher incentive compensation as a result of the higher share price.

[1] Non-GAAP financial measure - see "Frequently used terms" section for definition and reconciliation.

Liquidity and capital resources

Sources and uses of cash

The company issues long-term debt from time to time and maintains a commercial paper program. However, internally generated funds cover the majority of its financial requirements. Cash that may be temporarily surplus to the company's immediate needs is carefully managed through counterparty quality and investment guidelines to ensure that it is secure and readily available to meet the company's cash requirements and to optimize returns.

Cash flows from operating activities are highly dependent on crude oil and natural gas prices, as well as petroleum and chemical product margins. In addition, to provide for cash flow in future periods, the company needs to continually find and develop new resources, and continue to develop and apply new technologies to existing fields in order to maintain or increase production.

The company's financial strength enables it to make large, long-term capital expenditures. The company's portfolio of development opportunities and the complementary nature of its business segments help mitigate the overall risks for the company and its cash flows. Further, due to its financial strength, debt capacity and portfolio of opportunities, the risk associated with delay of any single project would not have a significant impact on the company's liquidity or ability to generate sufficient cash flows for its operations and fixed commitments.

Funding of registered retirement plans complies with federal and provincial pension regulations, and the company makes contributions to the plans based on an independent actuarial valuation completed at least once every three years depending on funding status. The most recent valuation of the company's registered retirement plans was completed as at December 31, 2022. A valuation of the company's registered retirement plans as at December 31, 2025 is expected to be completed in 2026. The company contributed $148 million to the registered retirement plans in 2025. Future funding requirements are not expected to affect the company's existing capital investment plans or its ability to pursue new investment opportunities.

millions of Canadian dollars	**2025**	2024	2023
Cash flows from (used in):			
Operating activities	**6,708**	5,981	3,734
Investing activities	**(1,892)**	(1,825)	(1,694)
Financing activities	**(4,653)**	(4,041)	(4,925)
Increase (decrease) in cash and cash equivalents	**163**	115	(2,885)
Cash and cash equivalents at end of year	**1,142**	979	864

Cash flows from operating activities

2025
Cash flows from operating activities primarily reflect favourable working capital impacts.

2024
Cash flows from operating activities primarily reflect lower unfavourable working capital impacts mainly related to an income tax catch-up payment of $2.1 billion in the prior year.

Cash flows used in investing activities

2025
Cash flows used in investing activities primarily reflect higher additions to property, plant and equipment.

2024
Cash flows used in investing activities primarily reflect higher additions to property, plant and equipment.

Cash flows used in financing activities

2025
At the end of 2025, total debt outstanding was $3,997 million, compared with $4,011 million at the end of 2024.

During the fourth quarter of 2025, the company extended the maturity dates of its two existing $250 million committed lines of credit to November 2026 and November 2027, respectively.

The company has not drawn on any of its outstanding $500 million of available credit facilities.

2024
At the end of 2024, total debt outstanding was $4,011 million, compared with $4,132 million at the end of 2023.

In June 2024, the company extended the maturity date of its existing long-term, variable-rate, Canadian dollar loan from ExxonMobil to June 30, 2035. All other terms and conditions remain unchanged.

During the fourth quarter of 2024, the company extended the maturity dates of its two existing $250 million committed lines of credit to November 2025 and November 2026, respectively.

The company has not drawn on any of its outstanding $500 million of available credit facilities.

Share repurchases

millions of Canadian dollars, unless noted	**2025**	2024	2023
Share repurchases (a)	**3,180**	2,681	3,800
Number of shares purchased (millions) (a)	**25.5**	26.8	48.3

(a) Share repurchases were made under the company's normal course issuer bid program for the periods disclosed. A Substantial issuer bid was undertaken and commenced on November 3, 2023 and expired on December 8, 2023. Includes shares purchased from Exxon Mobil Corporation under and in connection with the normal course issuer bid and by way of a proportionate tender under the company's substantial issuer bids.

2025
On June 23, 2025, the company announced by news release that it had received final approval from the Toronto Stock Exchange for a new normal course issuer bid to continue its then-existing share purchase program. The program enabled the company to purchase up to a maximum of 25,452,248 common shares during the period June 29, 2025 to June 28, 2026. The program completed on December 17, 2025 as a result of the company purchasing the maximum allowable number of shares under the program.

2024
On June 24, 2024, the company announced that it had received final approval from the Toronto Stock Exchange for a new normal course issuer bid to continue its then-existing share purchase program. The program enabled the company to purchase up to a maximum of 26,791,840 common shares during the period June 29, 2024 to June 28, 2025. The program completed on December 19, 2024 as a result of the company purchasing the maximum allowable number of shares under the program.

Dividends

millions of Canadian dollars, unless noted	**2025**	2024	2023
Dividends paid	**1,401**	1,238	1,103
Per share dividend paid (dollars)	**2.76**	2.30	1.88

Financial strength

The table below shows the company’s consolidated debt-to-capital ratio at December 31. The data demonstrates the company’s creditworthiness:

percent	**2025**	2024	2023
Debt to capital (a)	**15**	15	16

(a) Debt, defined as the sum of “Notes and loans payable” and “Long-term debt” on the Consolidated balance sheet, divided by capital, defined as the sum of debt and “Total shareholders’ equity” on the Consolidated balance sheet.

Debt-related interest incurred in 2025, before capitalization of interest, was $131 million, compared with $192 million in 2024. The weighted-average interest rate on the company’s debt was 3.1 percent in 2025, compared with 4.7 percent in 2024.

The company’s financial strength represents a competitive advantage of strategic importance providing it the opportunity to readily access capital markets across a range of market conditions and enables the company to take on large, long-term capital commitments in the pursuit of maximizing shareholder value.

Contractual obligations

The company has contractual obligations involving commitments to third parties that impact its liquidity and capital resource needs. These contractual obligations are primarily for leases, debt, asset retirement obligations, pension and other postretirement benefits, other long-term obligations, and firm capital commitments. Further information on this topic can be found in notes 4, 5, 11, 13, 14 to the consolidated financial statements.

Other long-term purchase agreements are commitments that are non-cancellable, or cancellable only under certain conditions, as well as long-term commitments, other than unconditional purchase obligations. They include primarily raw material supply, transportation services agreements, and community benefits agreements. The total obligation at year-end 2025 was $14.5 billion, of which $1.5 billion is due in 2026, and $1.5 billion is due in 2027.

Litigation and other contingencies

As discussed in note 9 to the consolidated financial statements, a variety of claims have been made against Imperial and its subsidiaries. Based on a consideration of all relevant facts and circumstances, the company does not believe the ultimate outcome of any currently pending lawsuits against the company will have a material adverse effect on the company’s operations, financial condition, or financial statements taken as a whole.

Additionally, as discussed in note 9, Imperial was contingently liable at December 31, 2025, for guarantees relating to performance under contracts. These guarantees do not have a material effect on the company’s operations, financial condition, or financial statements taken as a whole.

There are no events or uncertainties beyond those already included in reported financial information that would indicate a material change in future operating results or financial condition.

Capital and exploration expenditures

Capital and exploration expenditures represent the combined total of additions at cost to property, plant and equipment, additions to finance leases, additional investments and acquisitions; exploration expenses on a before-tax basis from the Consolidated statement of income; and the company's share of similar costs for equity companies. Capital and exploration expenditures exclude the purchase of carbon emission credits. While the company's management is responsible for all investments and elements of net income, particular focus is placed on managing the controllable aspects of this group of expenditures.

millions of Canadian dollars	**2025**	2024
Upstream (a)	**1,480**	1,078
Downstream	**412**	572
Chemical	**11**	30
Corporate and other	**124**	187
Total	**2,027**	1,867

(a) Exploration expenses included.

For the Upstream segment, capital and exploration expenditures were primarily related to sustaining activity in support of the company's oil sands and in-situ assets.

For the Downstream segment, capital expenditures were primarily for completing the Strathcona renewable diesel facility as well as other refinery and distribution projects to improve environmental performance, reliability, and energy efficiency.

Total capital and exploration expenditures are expected to range between $2.0 billion to $2.2 billion in 2026.

Expected capital and exploration expenditures for 2026 includes firm capital commitments of $585 million for the construction and purchase of fixed assets and other permanent investments. An additional $89 million of firm capital commitments have been made for years 2027 and beyond.

Actual spending could vary depending on the progress of individual projects.

Market risks

Crude oil, natural gas, petroleum product and chemical prices have fluctuated in response to changing market forces. The impacts of these price fluctuations on earnings from Upstream, Downstream and Chemical operations have varied.

The company's earnings are influenced by North American crude oil benchmark prices as well as changes in the differentials between these benchmarks and western Canadian prices for light and heavy crude oil. The company's integrated business model reduces its risk from changes in commodity prices. For instance, when differentials between North American crude benchmarks and western Canadian prices widen, the company is able to mitigate the impact of widening differentials on the Upstream through integration with Downstream investments in refineries and pipeline commitments.

In the competitive downstream and chemical environments, earnings are primarily determined by margin capture rather than absolute price levels on products sold. Refining margins are a function of the difference between what a refiner pays for its raw materials (primarily crude oil) and the market prices for the range of products produced. These prices, in turn, depend on global and regional supply/demand balances, inventory levels, refinery operations, import/export balances and weather.

Industry crude oil commodity prices and petroleum and chemical product prices are commonly benchmarked in U.S. dollars. The majority of the company'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 is exposed to changes in interest rates, primarily on its debt which carries floating interest rates. The impact of a quarter percent change in interest rates affecting the company's debt would not be material to earnings or cash flow. The company has access to significant sources of long-term and short-term liquidity. Internally generated funds are expected to cover the majority of financial requirements, supplemented by long-term and short-term debt as needed.

The company's potential exposure to commodity price and margin, and Canadian/U.S. dollar exchange rate fluctuations, is summarized in the earnings sensitivities table, which shows the estimated annual effect, under current conditions, on the company's after-tax net income. For any given period, the extent of actual benefit or detriment will be dependent on the price movements of individual types of crude oil and products, production and sales volumes, transportation capacity, costs and egress methods, and other factors. Accordingly, changes in benchmark prices for crude oil and crude oil differentials, and other factors listed in the table following, only provide broad indicators of changes in the earnings experienced in any particular period.

Earnings sensitivities (a)

millions of Canadian dollars, after-tax		
One dollar (U.S.) per barrel increase (decrease) in crude oil prices	+ (-)	**115**
One dollar (U.S.) per barrel increase (decrease) in refining 2-1-1 margins (b)	+ (-)	**145**
One cent decrease (increase) in the value of the Canadian dollar versus the U.S. dollar	+ (-)	**130**

(a) Each sensitivity calculation shows the annual impact on net income resulting from a change in one factor, after tax and royalties, and holding all other factors constant. These sensitivities have been updated to reflect current market conditions. They may not apply proportionately to larger fluctuations.
(b) The 2-1-1 crack spread is an indicator of the refining margin generated by converting two barrels of crude oil into one barrel of gasoline and one barrel of diesel.

The demand for crude oil, petroleum products and petrochemical products are generally linked closely with economic growth. The occurrence of recessions or other periods of low or negative economic growth will typically have a direct adverse impact on the company's financial results. Although price levels of crude oil may rise and fall significantly over the short to medium-term due to global economic conditions, political events, decisions by OPEC or OPEC+, governments and other factors, industry economics over the long-term will continue to be driven by market supply and demand. The company evaluates investments over a range of prices, including estimated greenhouse gas emission costs.

The global energy markets can give rise to extended periods in which market conditions are adverse to one or more of the company's businesses. Such conditions, along with the capital-intensive nature of the industry and very long lead times associated with many of the company's projects, underscore the importance of maintaining a strong financial position. Management views the company's financial strength as a competitive advantage.

In general, segment results are not dependent on the ability to sell and/or purchase products to/from other segments. Where such intersegment sales take place, they are the result of efficiencies and competitive advantages from integrated business segments and refinery and chemical complexes. The company's intersegment sales include crude oil produced by the Upstream and sold to the Downstream, as well as sales between refineries and the chemical plant related to raw materials, feedstocks and finished products. All intersegment sales are at market based prices. Refer to note 2 for additional information on intersegment revenue.

The company has an active asset management program in which nonstrategic assets are considered for divestment. The asset management program includes a disciplined, regular review to ensure that assets are contributing to the company's strategic objectives.

Risk management

The company's size, strong capital structure and the complementary nature of its business segments reduces the company's enterprise-wide risk from changes in commodity prices and currency exchange rates. In addition, the company may use commodity-based contracts, including derivatives, to manage commodity price risk and to generate returns from trading. The company's derivatives are not accounted for under hedge accounting. Credit risk associated with the company's derivative position is mitigated by several factors, including the use of derivative clearing exchanges and the quality of and financial limits placed on derivative counterparties. No material market or credit risks to the company's financial position, results of operations or liquidity exist as a result of the derivatives described in note 6. The company maintains a system of controls that includes the authorization, reporting and monitoring of derivative activity.

Critical accounting estimates

The company’s financial statements have been prepared in accordance with United States Generally Accepted Accounting Principles (U.S. GAAP). U.S. GAAP requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. The company’s accounting and financial reporting fairly reflect its integrated business model involving exploration for, and production of, crude oil and natural gas; manufacture, trade, transport and sale of crude oil, natural gas, petroleum products, petrochemicals and a variety of specialty products; and pursuit of lower-emission business opportunities including carbon capture and storage, hydrogen, lower-emission fuels, and lithium. The company does not use financing structures for the purpose of altering accounting outcomes or removing debt from the balance sheet. The company’s significant accounting policies are summarized in note 1 to the consolidated financial statements.

Oil and natural gas reserves

Evaluations of oil and natural gas reserves are important to the effective management of upstream assets. They are an integral part of investment decisions about oil and gas properties such as whether development should proceed.

The estimation of proved reserve volumes, which is based on the requirement of reasonable certainty, is an ongoing process based on rigorous technical evaluations, commercial and market assessments, detailed analysis of reservoir and well performance, development and production costs, and other factors. The estimation of proved reserves is controlled by the company through long-standing approval guidelines. Reserves changes are made within a well-established, disciplined process driven by qualified geoscience and engineering professionals, assisted by the reserves management group which has significant technical experience, culminating in reviews with and approval by senior management and the company’s board of directors. Notably, the company does not use specific quantitative reserves targets to determine compensation. Key features of the reserves estimation process are covered in "Disclosure of reserves" in Item 1.

Oil and natural gas reserves include both proved and unproved reserves.

- Proved oil and natural gas reserves are determined in accordance with U.S. Securities and Exchange Commission (SEC) requirements. Proved reserves are those quantities of oil and natural gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible under existing economic and operating conditions and government regulations. Proved reserves are determined using the average of first-day-of-the-month oil and natural gas prices during the reporting year.

  Proved reserves can be further subdivided into developed and undeveloped reserves. Proved developed reserves include amounts which are expected to be recovered through existing wells, facilities, or mining activities with existing equipment and operating methods. Proved undeveloped reserves include amounts expected to be recovered from new wells, existing wells, facilities, or mining activities, where a relatively major capital expenditure is required. Proved undeveloped reserves are recognized when a development plan has been adopted indicating that the reserves are scheduled to be developed within five years, unless specific circumstances support a longer period of time.

  The company is reasonably certain that proved reserves will be produced. However, the timing and amount recovered can be affected by a number of factors, including completion and optimization of development projects, reservoir performance, and facility processing capacity.

- Unproved reserves are quantities of oil and natural gas with less than reasonable certainty of recoverability and include probable reserves. Probable reserves are reserves that, together with proved reserves, are as likely as not to be recovered.

Revisions in previously estimated volumes of proved reserves for existing fields can occur due to the evaluation or re-evaluation of already available geologic, reservoir or production data; new geologic, reservoir or production data; or changes in the average of first-day-of-the-month oil and natural gas prices and/or costs that are used in the estimation of reserves. Revisions can also result from significant changes in either development strategy or production equipment and facility capacity.

In 2023, upward revisions of proved bitumen of 0.1 billion barrels were driven by lower royalty obligations associated with lower pricing and minor technical revisions at Cold Lake and Kearl. A slight increase in proved reserves for synthetic crude oil is associated with lower royalty obligations associated with pricing. Conventional proved liquids reserves decreased to zero under existing pricing and operating conditions.

In 2024, upward revisions of proved bitumen of 0.1 billion barrels were primarily driven by updates to the Kearl geological model, Kearl well density, and Cold Lake infill drilling, partially offset by reductions associated with higher royalty obligations and Kearl pit limit updates. A decrease to synthetic oil proved reserves is associated with regulatory approval for ore sterilization at Syncrude.

In 2025, upward revisions of proved bitumen were primarily driven by steam scheduling, development drilling, Liquid Addition to Steam for Enhanced Recovery (LASER) process at Cold Lake and lower royalty obligations associated with pricing for both Kearl and Cold Lake. An increase in proved reserves for synthetic crude oil is associated with lower royalty obligation.

Under the terms of certain contractual arrangements or government royalty regimes, lower prices can also increase proved reserves attributable to the company. The company's operating decisions and its outlook for future production volumes are not impacted by proved reserves as disclosed under the SEC definition.

Unit-of-production depreciation
Oil and natural gas reserve volumes are used as the basis to calculate unit-of-production depreciation rates for most upstream assets. Depreciation is calculated by taking the ratio of asset cost to total proved reserves or proved developed reserves applied to actual production. The volumes produced and asset cost are known, while proved reserves are based on estimates that are subject to some variability.

In the event that the unit-of-production method does not result in an equitable allocation of cost over the economic life of an upstream asset, an alternative method is used. The straight-line method is used in limited situations where the expected life of the asset does not reasonably correlate with that of the underlying reserves. For example, certain assets used in the production of oil and natural gas have a shorter life than the reserves, and as such, the company uses straight-line depreciation to ensure the asset is fully depreciated by the end of its useful life.

To the extent that proved reserves for a property are substantially de-booked and that property continues to produce such that the resulting depreciation charge does not result in an equitable allocation of cost over the expected life, assets will be depreciated using a unit-of-production method based on reserves determined at the most recent SEC price which results in a more meaningful quantity of proved reserves, appropriately adjusted for production and technical changes.

Impact of oil and gas reserves and prices and margins on testing for impairment
The company tests assets or groups of assets for recoverability on an ongoing basis whenever events or changes in circumstances indicate that the carrying amounts may not be recoverable. The company has a robust process to monitor for indicators of potential impairment across its asset groups throughout the year. This process is aligned with the requirements of *ASC 360* and *ASC 932* and relies, in part, on the company's planning and budgeting cycle.

Because the lifespans of the vast majority of the company's major assets are measured in decades, the future cash flows of these assets are predominantly based on long-term oil and natural gas commodity prices and industry margins, development and production costs. Significant reductions in the company's view of oil or natural gas commodity prices or margin ranges, especially the longer-term prices and margins, and changes in the development plans, including decisions to defer, reduce or eliminate planned capital spending, can be an indicator of potential impairment. Other events or changes in circumstances, including indicators outlined in *ASC 360,* can be indicators of potential impairment as well.

In general, the company does not view temporarily low prices or margins as an indication of impairment. Management believes that prices over the long term must be sufficient to generate investments in energy supply to meet global demand. Although prices will occasionally drop significantly, industry prices over the long term will continue to be driven by market supply and demand fundamentals. On the supply side, industry production from mature fields is declining. This is being offset by investments to generate production from new discoveries, field developments, and technology and efficiency advancements. OPEC+ investment activities and production policies also have an impact on world oil supplies. The demand side is largely a function of general economic activities, alternative energy sources and levels of prosperity. During the lifespan of its major assets, the company expects that oil and gas prices and industry margins will experience significant volatility. Consequently, these assets will experience periods of higher earnings and periods of lower earnings, or even losses. In assessing whether events or changes in circumstances indicate the carrying value of an asset may not be recoverable, the company considers recent periods of operating losses in the context of its longer-term view of prices and margins.

Global Outlook and cash flow assessment
The annual planning and budgeting process, known as the company plan, is the mechanism by which resources (capital, operating expenses and people) are allocated across the company. The foundation for the energy supply and demand assumptions supporting the company plan begins with Exxon Mobil Corporation's *Global Outlook* (the Outlook), which contains demand and supply projections based on its assessment of current trends in technology, government policies, consumer preferences, geopolitics, economic development, and other factors.

Reflective of the existing global policy environment, the Outlook does not attempt to project the degree of necessary future policy and technology advancement and deployment for the world to meet net zero by 2050. As future policies and technology advancements emerge, they will be incorporated into the Outlook, and consequently, the company's business plans will be updated accordingly.

If events or changes in circumstances indicate that the carrying value of an asset may not be recoverable, the company estimates the future undiscounted cash flows of the affected properties to judge the recoverability of carrying amounts. In performing this assessment, assets are grouped at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. Cash flows used in recoverability assessments are based on the assumptions developed in the company plan, which is reviewed and approved by the board of directors, and are consistent with the criteria management uses to evaluate investment opportunities. These evaluations make use of the company's assumptions of future capital allocations, crude oil and natural gas commodity prices including price differentials, refining and chemical margins, volumes, development and operating costs, including greenhouse gas emissions prices, and foreign currency exchange rates. Volumes are based on projected field and facility production profiles, throughput, or sales. Management's estimate of upstream production volumes used for projected cash flows makes use of proved reserve quantities and may include risk-adjusted unproved reserve quantities. The greenhouse gas emission prices reflect existing or anticipated policy actions of applicable provincial and federal governments. While third-party scenarios may be used to test the resiliency of company's businesses or strategies, they are not used as a basis for developing future cash flows for impairment assessments.

Fair value of impaired assets
An asset group is impaired if its estimated future undiscounted cash flows are less than the asset group's carrying value. Impairments are measured by the excess of the carrying value over fair value. The assessment of fair value is based on the views of a likely market participant. The principal parameters used to establish fair value include estimates of acreage values and flowing production metrics from comparable market transactions, market-based estimates of historical cash flow multiples, and discounted cash flows. Inputs and assumptions used in discounted cash flow models include estimates of future production volumes, throughput and product sales volumes, commodity prices (which are consistent with the average of third-party industry experts and government agencies), refining and chemical margins, drilling and development costs, operating costs, and discount rates which are reflective of the characteristics of the asset group.

Other impairment estimates
Unproved properties are assessed periodically to determine whether they have been impaired. Significant unproved properties are assessed for impairment individually, and valuation allowances against the capitalized costs are recorded based on the company's future development plans, the estimated economic chance of success and the length of time that the company expects to hold the properties. Properties that are not individually significant are aggregated by groups and amortized based on development risk and average holding period.

Long-lived assets that are held for sale are evaluated for possible impairment by comparing the carrying value of the asset with its fair value less the cost to sell. If the net book value exceeds the fair value less cost to sell, the assets are considered impaired and adjusted to the lower value. Judgment is required to determine if assets are held for sale, and to determine the fair value less cost to sell.

Investments accounted for by the equity method are assessed for possible impairment when events or changes in circumstances indicate that the carrying value of an investment may not be recoverable. Examples of key indicators include a history of operating losses, negative earnings and cash flow outlook, significant downward revisions to oil and gas reserves, and the financial condition and prospects for the investee's business segment or geographic region. If the decline in value of the investment is other than temporary, the carrying value of the investment is written down to fair value. In the absence of market prices for the investment, discounted cash flows are used to assess fair value, which requires significant judgment.

Recent impairments
In 2025, the company signed an agreement to sell the Calgary Imperial Campus which resulted in a non-cash impairment charge of $306 million after-tax in the Corporate and other segment.

Factors which could put further assets at risk of impairment in the future include reductions in the company's price or margin outlooks, changes in the allocation of capital or development plans, reduced long-term demand for the company's products and operating cost increases which exceed the pace of efficiencies or the pace of oil and natural gas price increases or margins. However, due to the inherent difficulty in predicting future commodity prices or margins, and the relationship between industry prices and costs, it is not practicable to reasonably estimate the existence or range of any potential future impairment charges related to the company's long-lived assets.

Supplemental information regarding oil and gas results of operations, capitalized costs and reserves is provided following the notes to consolidated financial statements.

Pension benefits
The company's pension plan is managed in compliance with the requirements of governmental authorities and meets funding levels as determined by independent third-party actuaries. Pension accounting requires explicit assumptions regarding, among others, the discount rate for the benefit obligations, the expected rate of return on plan assets and the long-term rate of future compensation increases. All pension assumptions are reviewed annually by senior management. These assumptions are adjusted only as appropriate to reflect long-term changes in market rates and outlook. The long-term expected rate of return on plan assets of 4.4 percent used in 2025 compares to actual returns of 4.5 percent and 5.6 percent achieved over the last 10- and 20-year periods respectively, ending December 31, 2025. If different assumptions are used, the obligation and expense could increase or decrease as a result. As an indication of the company's potential exposure to changes in the critical assumptions, such as the expected rate of return on plan assets, a reduction of 1 percent in the long-term rate of return on plan assets would increase the annual pension expense by approximately $85 million before tax. At the company, differences between actual returns on plan assets and the long-term expected returns are not recorded in pension expense in the year the differences occur. Such differences are deferred, along with other actuarial gains and losses, and are amortized into pension expense over the expected average remaining service life of employees. Employee benefits expense represented about 1 percent of total expenses in 2025.

Asset retirement obligations
The company is subject to retirement obligations for certain assets. The fair values of these obligations are recorded as liabilities on a discounted basis, which is typically at the time the assets are installed. In the estimation of fair value, the company uses assumptions and judgments regarding such factors as the existence of a legal obligation for an asset retirement obligation, technical assessments of the assets, estimated amounts and timing of settlements, discount rates, and inflation rates. Note 5 to the consolidated financial statements provides a three-year continuity table detailing the changes in asset retirement obligations.

Tax contingencies
The operations of the company are complex, and related tax interpretations, regulations and legislation are continually changing.

The benefits of uncertain tax positions that the company has taken or expects to take in its income tax returns are recognized in the financial statements if management concludes that it is more likely than not that the position will be sustained with the tax authorities. For a position that is likely to be sustained, the benefit recognized in the financial statements is measured at the largest amount that is greater than 50 percent likely of being realized. Significant management judgment is required in the accounting for income tax contingencies and tax disputes because the outcomes are often difficult to predict. The company's unrecognized tax benefits and a description of open tax years are summarized in note 3 to the consolidated financial statements.

Management's report on internal control over financial reporting

Management, including the company's chief executive officer and principal accounting officer and principal financial officer, is responsible for establishing and maintaining adequate internal control over the company's financial reporting. Management conducted an evaluation of the effectiveness of internal control over financial reporting based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Imperial Oil Limited's internal control over financial reporting was effective as of December 31, 2025.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the company's internal control over financial reporting as of December 31, 2025, as stated in their report which is included herein.

/s/ John R. Whelan

John R. Whelan
Chairman, president and chief executive officer
(Principal executive officer)

/s/ Daniel E. Lyons

Daniel E. Lyons
Senior vice-president,
finance and administration, and controller
(Principal accounting officer and principal financial officer)

February 18, 2026

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Imperial Oil Limited

Opinions on the Financial Statements and Internal Control over Financial Reporting
We have audited the accompanying consolidated balance sheets of Imperial Oil Limited and its subsidiaries (the Company) as of December 31, 2025 and 2024, and the related consolidated statements of income, of comprehensive income, of shareholders' equity and of cash flows for each of the three years in the period ended December 31, 2025, including the related notes (collectively referred to as the consolidated financial statements). We also have audited the Company's internal control over financial reporting as of December 31, 2025, based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2025, based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the COSO.

Basis for Opinions
The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

The Impact of Proved Developed Oil and Natural Gas Reserve Volumes on Upstream Property, Plant and Equipment, Net

As described in Notes 1 and 2 to the consolidated financial statements, the Company’s consolidated upstream property, plant and equipment (PP&E), net balance was $26,037 million as of December 31, 2025, and the related depreciation and depletion expense for the year ended December 31, 2025 was $1,906 million. Management uses the successful efforts method to account for its exploration and production activities. Costs incurred to purchase, lease or otherwise acquire a property (whether unproved or proved) are capitalized when incurred. As disclosed by management, proved oil and natural gas reserve volumes are used as the basis to calculate unit-of-production depreciation rates for most upstream assets. The estimation of proved oil and natural gas reserve volumes is an ongoing process based on technical evaluations, commercial and market assessments, detailed analysis of reservoir and well performance, development and production costs, and other factors. As further disclosed by management, reserves changes are made within a well-established, disciplined process driven by qualified geoscience and engineering professionals, assisted by the reserves management group (together, management’s specialists).

The principal considerations for our determination that performing procedures relating to the impact of proved developed oil and natural gas reserve volumes on upstream PP&E, net is a critical audit matter are (i) the significant judgment by management, including the use of management’s specialists, when developing the estimates of proved developed oil and natural gas reserve volumes, and (ii) a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating audit evidence related to the data, methods, and assumptions used by management and its specialists in developing the estimates of proved developed oil and natural gas reserve volumes.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management’s estimates of proved developed oil and natural gas reserve volumes. The work of management’s specialists was used in performing the procedures to evaluate the reasonableness of the proved developed oil and natural gas reserve volumes. As a basis for using this work, management’s specialists’ qualifications were understood and the Company’s relationship with management’s specialists was assessed. The procedures performed, also included i) evaluating the methods and assumptions used by management’s specialists, ii) testing the completeness and accuracy of the data used by management’s specialists related to historical production volumes, and iii) evaluating management’s specialists’ findings related to future production volumes by comparing the future production volumes to relevant historical and current period production volumes, as applicable.

/s/PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Canada
February 18, 2026

We have served as the Company’s auditor since 1934.

Consolidated statement of income (U.S. GAAP)

millions of Canadian dollars For the years ended December 31	**2025**	2024	2023
Revenues and other income			
Revenues (a)	**46,918**	51,359	50,702
Investment and other income (note 8)	**160**	173	267
Total revenues and other income	**47,078**	51,532	50,969
Expenses			
Exploration (note 15)	**7**	3	5
Purchases of crude oil and products (b)	**29,807**	33,184	32,399
Production and manufacturing (c)	**7,269**	6,599	6,879
Selling and general (c) (note 11)	**1,386**	945	857
Federal excise tax and fuel charge	**1,715**	2,535	2,402
Depreciation and depletion (includes impairments) (note 11)	**2,579**	1,983	1,907
Non-service pension and postretirement benefit	**41**	3	82
Financing (d) (note 12)	**12**	41	69
Total expenses	**42,816**	45,293	44,600
Income (loss) before income taxes	**4,262**	6,239	6,369
Income taxes (note 3)	**994**	1,449	1,480
Net income (loss)	**3,268**	4,790	4,889
Per share information (Canadian dollars)			
Net income (loss) per common share - basic (note 10)	**6.50**	9.05	8.51
Net income (loss) per common share - diluted (note 10)	**6.48**	9.03	8.49
(a) Amounts from related parties included in revenues (note 16).	**13,534**	14,654	16,166
(b) Amounts to related parties included in purchases of crude oil and products (note 16).	**5,369**	6,651	6,747
(c) Amounts to related parties included in production and manufacturing, and selling and general expenses (note 16).	**568**	541	473
(d) Amounts to related parties included in financing (note 16).	**97**	161	169

The information in the notes to consolidated financial statements is an integral part of these statements.

Consolidated statement of comprehensive income (U.S. GAAP)

millions of Canadian dollars For the years ended December 31	**2025**	2024	2023
Net income (loss)	**3,268**	4,790	4,889
Other comprehensive income (loss), net of income taxes			
Postretirement benefits liability adjustment (excluding amortization)	**181**	412	(206)
Amortization of postretirement benefits liability adjustment included in net benefit costs	**19**	51	41
Total other comprehensive income (loss)	**200**	463	(165)
Comprehensive income (loss)	**3,468**	5,253	4,724

The information in the notes to consolidated financial statements is an integral part of these statements.

Consolidated balance sheet (U.S. GAAP)

millions of Canadian dollars At December 31	**2025**	2024
Assets		
Current assets		
Cash and cash equivalents	**1,142**	979
Accounts receivable - net (a)	**4,371**	5,758
Inventories of crude oil and products (note 11)	**2,211**	1,642
Materials, supplies and prepaid expenses	**693**	975
Total current assets	**8,417**	9,354
Investments and long-term receivables (b)	**1,103**	1,084
Property, plant and equipment, less accumulated depreciation and depletion (note 11)	**30,863**	30,807
Goodwill	**166**	166
Other assets, including intangibles - net	**1,760**	1,527
Total assets	**42,309**	42,938
Liabilities		
Current liabilities		
Notes and loans payable (note 12)	**19**	19
Accounts payable and accrued liabilities (a) (note 5, 11)	**6,595**	6,907
Income taxes payable	**2**	81
Total current liabilities	**6,616**	7,007
Long-term debt (c) (note 14)	**3,978**	3,992
Other long-term obligations (note 5, 11)	**4,959**	3,870
Deferred income tax liabilities (note 3)	**4,502**	4,596
Total liabilities	**20,055**	19,465
Commitments and contingent liabilities (note 9)		
Shareholders' equity		
Common shares at stated value (d) (note 10)	**895**	942
Earnings reinvested	**21,373**	22,745
Accumulated other comprehensive income (loss) (note 17)	**(14)**	(214)
Total shareholders' equity	**22,254**	23,473
Total liabilities and shareholders' equity	**42,309**	42,938
(a) Accounts receivable - net included net amounts receivable from related parties (note 16).	**399**	756
(b) Investments and long-term receivables included amounts from related parties (note 16).	**251**	266
(c) Long-term debt included amounts to related parties (note 16).	**3,447**	3,447
(d) Number of common shares authorized (millions) (note 10).	**1,100**	1,100
Number of common shares outstanding (millions) (note 10).	**484**	509

The information in the notes to consolidated financial statements is an integral part of these statements.

Approved by the directors.

/s/ John R. Whelan

John R. Whelan
Chairman, president and
chief executive officer

/s/ Daniel E. Lyons

Daniel E. Lyons
Senior vice-president
finance and administration, and controller

Consolidated statement of shareholders' equity (U.S. GAAP)

millions of Canadian dollars At December 31	**2025**	2024	2023
Common shares at stated value (note 10)			
At beginning of year	**942**	992	1,079
Share purchases at stated value	**(47)**	(50)	(87)
At end of year	**895**	942	992
Earnings reinvested			
At beginning of year	**22,745**	21,907	21,846
Net income (loss) for the year	**3,268**	4,790	4,889
Share purchases in excess of stated value	**(3,196)**	(2,685)	(3,713)
Dividends declared	**(1,444)**	(1,267)	(1,115)
At end of year	**21,373**	22,745	21,907
Accumulated other comprehensive income (loss) (note 17)			
At beginning of year	**(214)**	(677)	(512)
Other comprehensive income (loss)	**200**	463	(165)
At end of year	**(14)**	(214)	(677)
Shareholders' equity at end of year	**22,254**	23,473	22,222

The information in the notes to consolidated financial statements is an integral part of these statements.

Consolidated statement of cash flows (U.S. GAAP)

millions of Canadian dollars For the years ended December 31	**2025**	2024	2023
Operating activities			
Net income (loss)	**3,268**	4,790	4,889
Adjustments for non-cash items:			
Depreciation and depletion (includes impairments) (note 11)	**2,579**	1,983	1,907
(Gain) loss on asset sales (note 8)	**5**	(18)	(73)
Deferred income taxes and other	**(156)**	(142)	(85)
Changes in operating assets and liabilities:			
Accounts receivable	**1,387**	(1,276)	237
Inventories, materials, supplies and prepaid expenses	**(287)**	335	(688)
Income taxes payable	**(79)**	(170)	(2,331)
Accounts payable and accrued liabilities	**(346)**	616	81
All other items - net (c)	**337**	(137)	(203)
Cash flows from (used in) operating activities	**6,708**	5,981	3,734
Investing activities			
Additions to property, plant and equipment	**(2,005)**	(1,867)	(1,785)
Proceeds from asset sales (note 8)	**101**	25	86
Additional investments	**(4)**	—	—
Loans to equity companies - net	**16**	17	5
Cash flows from (used in) investing activities	**(1,892)**	(1,825)	(1,694)
Financing activities			
Short-term debt - net (note 12)	**—**	(100)	—
Finance lease obligations - reduction (note 14)	**(18)**	(22)	(22)
Dividends paid	**(1,401)**	(1,238)	(1,103)
Common shares purchased (b) (note 10)	**(3,234)**	(2,681)	(3,800)
Cash flows from (used in) financing activities	**(4,653)**	(4,041)	(4,925)
Increase (decrease) in cash and cash equivalents	**163**	115	(2,885)
Cash and cash equivalents at beginning of year	**979**	864	3,749
Cash and cash equivalents at end of year (a)	**1,142**	979	864

(a) Cash is composed of cash in bank and cash equivalents at cost. Cash equivalents are all highly liquid securities with maturity of three months or less.

(b) Includes 2 percent tax paid on repurchases of equity.

(c) Includes contributions to registered pension plans.	**(148)**	(150)	(148)
Interest (paid), net of capitalization.	**(28)**	(42)	(69)

The information in the notes to consolidated financial statements is an integral part of these statements.

Notes to consolidated financial statements

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

The company's principal business involves exploration for, and production of, crude oil and natural gas; manufacture, trade, transport and sale of crude oil, natural gas, petroleum products, petrochemicals and a variety of specialty products; and pursuit of lower-emission business opportunities including carbon capture and storage, hydrogen, lower-emission fuels, and lithium.

The consolidated financial statements have been prepared in accordance with United States Generally Accepted Accounting Principles (U.S. GAAP), which requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. Actual results could differ from these estimates. All amounts are in Canadian dollars unless otherwise indicated.

Note 1. Summary of significant accounting policies

Principles of consolidation
The consolidated financial statements include the accounts of subsidiaries the company controls. Intercompany accounts and transactions are eliminated. Subsidiaries include those companies in which Imperial has both an equity interest and the continuing ability to unilaterally determine strategic, operating, investing and financing policies. Imperial Oil Resources Limited and Canada Imperial Oil Limited are significant subsidiaries included in the consolidated financial statements and are wholly owned by Imperial Oil Limited. The consolidated financial statements also include the company's share of the undivided interest in certain upstream assets, liabilities, revenues and expenses, including its 70.96 percent interest in the Kearl joint venture and its 25 percent interest in the Syncrude joint venture.

Revenues
The company generally sells crude oil, natural gas and petroleum and chemical products under short-term agreements at prevailing market prices. In some cases, products may be sold under long-term agreements, with periodic price adjustments to reflect market conditions.

Revenue is recognized at the amount the company expects to receive when the customer has taken control, which is typically when title transfers and the customer has assumed the risks and rewards of ownership. The prices of certain sales are based on price indices that are sometimes not available until the next period. In such cases, estimated realizations are accrued when the sale is recognized, and are finalized when final information is available. Such adjustments to revenue from performance obligations satisfied in previous periods are not significant. Payment for revenue transactions is typically due within 30 days.

Revenues include amounts billed to customers for shipping and handling. Shipping and handling costs incurred up to the point of final storage prior to delivery to a customer are included in "Purchases of crude oil and products" in the Consolidated statement of income. Delivery costs from final storage to customer are recorded as a marketing expense in "Selling and general" expenses. The company does not enter into ongoing arrangements whereby it is required to repurchase its products, nor does the company provide the customer with a right of return.

Future volume delivery obligations that are unsatisfied at the end of the period are expected to be fulfilled through ordinary production or purchases. These performance obligations are based on market prices at the time of the transaction and are fully constrained due to market price volatility.

Purchases and sales of inventory with the same counterparty that are entered into in contemplation of one another are combined and recorded as exchanges measured at the book value of the item sold.

"Revenues" and "Accounts receivable - net" include revenue and receivables both within the scope of *ASC 606 Revenue from Contracts with Customers*, and those outside the scope of *ASC 606*. Long-term receivables are primarily from receivables outside the scope of *ASC 606*. Contract assets are mainly from marketing assistance programs and are not significant. Contract liabilities are mainly customer prepayments and accruals of expected volume discounts, and are not significant.

Consumer and other taxes
Taxes levied on the consumer and collected by the company are excluded from the Consolidated statement of income. These are primarily provincial taxes on motor fuels, the federal goods and services tax and the federal/ provincial harmonized sales tax. Similar taxes, for which the company is not considered to be an agent for the government, are reported on a gross basis (included in both "Revenues" and "Federal excise tax and fuel charge").

Derivative instruments
The company may use derivative instruments for trading purposes and to offset exposures associated with commodity prices, currency exchange rates and interest rates that arise from existing assets, liabilities, firm commitments and forecasted transactions. All derivative instruments, except those designated as normal purchase and normal sale, are recorded at fair value. Derivative assets and liabilities with the same counterparty are netted if the right of offset exists and certain other criteria are met. Collateral payables or receivables are netted against derivative assets and derivative liabilities, respectively.

Recognition and classification of the gain or loss that results from adjusting a derivative to fair value depends on the purpose for the derivative. The gains and losses resulting from changes in the fair value of derivatives are recorded under "Revenues" in the Consolidated statement of income.

Fair value
Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. Hierarchy levels 1, 2 and 3 are terms for the priority of inputs to valuation techniques used to measure fair value. Hierarchy level 1 inputs are quoted prices in active markets for identical assets or liabilities. Hierarchy level 2 inputs are inputs other than quoted prices included within level 1 that are directly or indirectly observable for the asset or liability. Hierarchy level 3 inputs are inputs that are not observable in the market.

Inventories
Inventories are recorded at the lower of current market value or cost. The cost of crude oil and products is determined primarily using the last-in, first-out (LIFO) method. LIFO was selected over the alternative first-in, first-out and average cost methods because it provides a better matching of current costs with the revenues generated in the period.

Inventory costs include expenditures and other charges (including depreciation), directly and indirectly incurred in bringing the inventory to its existing condition and location. Selling and general expenses are reported as period costs and excluded from inventory costs. Inventories of materials and supplies are valued at cost or less.

Investments
The company’s interests in the underlying net assets of affiliates it does not control, but over which it exercises significant influence, are accounted for using the equity method. They are recorded at the original cost of the investment plus the company’s share of earnings since the investment was made, less dividends received. The company’s share of the after-tax earnings of these investments is included in “Investment and other income” in the Consolidated statement of income. Investments in equity securities, other than consolidated subsidiaries and equity method investments, are measured at fair value, with changes in the fair value recognized in net income. The company uses a modified approach for equity securities that do not have a readily determinable fair value. This modified approach measures investments at cost minus impairment, if any, plus or minus changes resulting from observable price changes in orderly transactions in similar investments of the same issuer. Dividends from these investments are included in “Investment and other income”.

These investments represent interests in non-publicly traded pipeline companies that facilitate the sale and purchase of liquids in the conduct of company operations. Other parties who also have an equity interest in these investments share in the risks and rewards according to their percentage of ownership. The company does not invest in these investments in order to remove liabilities from its balance sheet.

Property, plant and equipment
Cost basis
The company uses the "successful efforts" method to account for its exploration and production activities. Under this method, costs are accumulated on a field-by-field basis. Costs incurred to purchase, lease, or otherwise acquire a property (whether unproved or proved) are capitalized when incurred. Exploratory well costs are carried as an asset when the well has found a sufficient quantity of reserves to justify its completion as a producing well and where the company is making sufficient progress assessing the reserves and the economic and operating viability of the project. Exploratory well costs not meeting these criteria are charged to expense. Other exploratory expenditures, including geophysical costs and annual lease rentals, are expensed as incurred. Development costs, including costs of productive wells and development dry holes, are capitalized.

Interest costs incurred to finance expenditures during the construction phase of projects are capitalized as part of the historical cost of acquiring the constructed assets. The project construction phase commences with the development of the detailed engineering design and ends when the constructed assets are ready for their intended use. Capitalized interest costs are included in property, plant and equipment and are depreciated over the service life of the related assets.

Maintenance and repair costs, including planned major maintenance, are expensed as incurred. Improvements that increase or prolong the service life or capacity of an asset are capitalized.

Depreciation, depletion and amortization
Depreciation, depletion and amortization are primarily determined under either the unit-of-production method or the straight-line method, which is based on estimated asset service life taking obsolescence into consideration. Depreciation and depletion for assets associated with producing properties begin at the time when production commences on a regular basis. Depreciation for other assets begins when the asset is in place and ready for its intended use. Assets under construction are not depreciated or depleted.

Acquisition costs of proved properties are amortized using a unit-of-production method, computed on the basis of total proved oil and natural gas reserve volumes. Capitalized exploratory drilling and development costs associated with productive depletable extractive properties are amortized using the unit-of-production rates based on the amount of proved developed reserves of oil and gas that are estimated to be recoverable from existing facilities using current operating methods. Under the unit-of-production method, oil and natural gas volumes are considered produced once they have been measured through meters at custody transfer or sales transaction points at the outlet valve on the lease or field storage tank. In the event that the unit-of-production method does not result in an equitable allocation of cost over the economic life of an upstream asset, an alternative method is used. The straight-line method is used in limited situations where the expected life of the asset does not reasonably correlate with that of the underlying reserves. For example, certain assets used in the production of oil and natural gas have a shorter life than the reserves, and as such, the company uses straight-line depreciation to ensure the asset is fully depreciated by the end of its useful life. Investments in mining heavy equipment and certain ore processing plant assets at oil sands mining properties are depreciated on a straight-line basis over a maximum of 15 years and 50 years respectively. Depreciation of other plant and equipment is calculated using the straight-line method, based on the estimated service life of the asset.

To the extent that proved reserves for a property are substantially de-booked and that property continues to produce such that the resulting depreciation charge does not result in an equitable allocation of cost over the expected life, assets will be depreciated using a unit-of-production method based on reserves determined at the most recent SEC price which results in a more meaningful quantity of proved reserves, appropriately adjusted for production and technical changes.

Investments in refinery and chemical process manufacturing equipment are generally depreciated on a straight-line basis over a 25-year life. Maintenance and repairs, including planned major maintenance, are expensed as incurred. Major renewals and improvements are capitalized and the assets replaced are retired.

Impairment assessment
The company tests assets or groups of assets for recoverability on an ongoing basis whenever events or changes in circumstances indicate that the carrying amounts may not be recoverable.

Among the events or changes in circumstances which could indicate that the carrying value of an asset or asset group may not be recoverable are the following:

- a significant decrease in the market price of a long-lived asset;
- a significant adverse change in the extent or manner in which an asset is being used or in its physical condition, including a significant decrease in current and projected reserve volumes;
- a significant adverse change in legal factors or in the business climate that could affect the value, including an adverse action or assessment by a regulator;
- an accumulation of project costs significantly in excess of the amount originally expected;
- a current-period operating loss combined with a history and forecast of operating or cash flow losses; and
- a current expectation that, more likely than not, a long-lived asset will be sold or otherwise disposed of significantly before the end of its previously estimated useful life.

The company has a robust process to monitor for indicators of potential impairment across its asset groups throughout the year. This process is aligned with the requirements of *ASC 360* and *ASC 932* and relies, in part, on the company's planning and budgeting cycle. Asset valuation analysis, profitability reviews and other periodic control processes assist the company in assessing whether events or changes in circumstances indicate the carrying amounts of any of its assets may not be recoverable.

Because the lifespans of the vast majority of the company's major assets are measured in decades, the future cash flows of these assets are predominantly based on long-term oil and natural gas commodity prices and industry margins, development and production costs. Significant reductions in the company's view of oil or natural gas commodity prices or margin ranges, especially the longer-term prices and margins, and changes in the development plans, including decisions to defer, reduce or eliminate planned capital spending, can be an indicator of potential impairment. Other events or changes in circumstances, including indicators outlined in *ASC 360,* can be indicators of potential impairment as well.

In general, the company does not view temporarily low prices or margins as an indication of impairment. Management believes that prices over the long term must be sufficient to generate investments in energy supply to meet global demand. Although prices will occasionally drop significantly, industry prices over the long term will continue to be driven by market supply and demand fundamentals. On the supply side, industry production from mature fields is declining. This is being offset by investments to generate production from new discoveries, field developments, and technology and efficiency advancements. OPEC+ investment activities and production policies also have an impact on world oil supplies. The demand side is largely a function of general economic activities, alternative energy sources and levels of prosperity. During the lifespan of its major assets, the company expects that oil and gas prices and industry margins will experience significant volatility. Consequently, these assets will experience periods of higher earnings and periods of lower earnings, or even losses. In assessing whether events or changes in circumstances indicate the carrying value of an asset may not be recoverable, the company considers recent periods of operating losses in the context of its longer-term view of prices and margins.

In the Upstream, the standardized measure of discounted cash flows included in the "Supplemental information on oil and gas exploration and production activities" is required to use prices based on the average of first-day-of-month prices in the year. These prices represent discrete points in time and could be higher or lower than the company's price assumptions which are used for impairment assessments. The company believes the standardized measure does not provide a reliable estimate of the expected future cash flows to be obtained from the development and production of its oil and gas properties or of the value of its oil and gas reserves and therefore does not consider it relevant in determining whether events or changes in circumstances indicate the need for an impairment assessment.

Global Outlook and cash flow assessment
The annual planning and budgeting process, known as the company plan, is the mechanism by which resources (capital, operating expenses and people) are allocated across the company. The foundation for the energy supply and demand assumptions supporting the company plan begins with Exxon Mobil Corporation's *Global Outlook* (the Outlook), which contains demand and supply projections based on its assessment of current trends in technology, government policies, consumer preferences, geopolitics, economic development, and other factors.

Reflective of the existing global policy environment, the Outlook does not attempt to project the degree of necessary future policy and technology advancement and deployment for the world to meet net zero by 2050. As future policies and technology advancements emerge, they will be incorporated into the Outlook, and consequently, the company's business plans will be updated accordingly.

If events or changes in circumstances indicate that the carrying value of an asset may not be recoverable, the company estimates the future undiscounted cash flows of the affected properties to judge the recoverability of carrying amounts. In performing this assessment, assets are grouped at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. Cash flows used in recoverability assessments are based on the assumptions developed in the company plan, which is reviewed and approved by the board of directors, and are consistent with the criteria management uses to evaluate investment opportunities. These evaluations make use of the company's assumptions of future capital allocations, crude oil and natural gas commodity prices including price differentials, refining and chemical margins, volumes, development and operating costs, including greenhouse gas emissions prices, and foreign currency exchange rates. Volumes are based on projected field and facility production profiles, throughput, or sales. Management's estimate of upstream production volumes used for projected cash flows makes use of proved reserve quantities and may include risk-adjusted unproved reserve quantities. The greenhouse gas emission prices reflect existing or anticipated policy actions of applicable provincial and federal governments.

Fair value of impaired assets
An asset group is impaired if its estimated future undiscounted cash flows are less than the asset group's carrying value. Impairments are measured by the excess of the carrying value over fair value. The assessment of fair value is based on the views of a likely market participant. The principal parameters used to establish fair value include estimates of acreage values and flowing production metrics from comparable market transactions, market-based estimates of historical cash flow multiples, and discounted cash flows. Inputs and assumptions used in discounted cash flow models include estimates of future production volumes, throughput and product sales volumes, commodity prices (which are consistent with the average of third-party industry experts and government agencies), refining and chemical margins, drilling and development costs, operating costs, and discount rates which are reflective of the characteristics of the asset group.

Other impairment estimates
Unproved properties are assessed periodically to determine whether they have been impaired. Significant unproved properties are assessed for impairment individually, and valuation allowances against the capitalized costs are recorded based on the company's future development plans, the estimated economic chance of success and the length of time that the company expects to hold the properties. Properties that are not individually significant are aggregated by groups and amortized based on development risk and average holding period.

Long-lived assets that are held for sale are evaluated for possible impairment by comparing the carrying value of the asset with its fair value less the cost to sell. If the net book value exceeds the fair value less cost to sell, the assets are considered impaired and adjusted to the lower value. Gains on sales of proved and unproved properties are only recognized when there is neither uncertainty about the recovery of costs applicable to any interest retained nor any substantial obligation for future performance by the company.

Asset retirement obligations and other environmental liabilities
The company incurs retirement obligations for certain assets. The fair values of these obligations are recorded as liabilities on a discounted basis, which is typically at the time the assets are installed. In the estimation of fair value, the company uses assumptions and judgments regarding such factors as the existence of a legal obligation for an asset retirement obligation, technical assessments of the assets, estimated amounts and timing of settlements, discount rates, and inflation rates. Asset retirement obligations incurred in the current period were level 3 fair value measurements. The costs associated with these liabilities are capitalized as part of the related assets and depreciated as the reserves are produced. Over time, the liabilities are accreted for the change in their present value.

Asset retirement obligations for downstream and chemical facilities generally become firm at the time the facilities are permanently shut down and dismantled. These obligations may include the costs of asset disposal and additional soil remediation. However, these sites generally have indeterminate lives based on plans for continued operations, and as such, the fair value of the conditional legal obligations cannot be measured, since it is impossible to estimate the future settlement dates of such obligations. Note 5 to the consolidated financial statements provides a three-year continuity table detailing the changes in asset retirement obligations.

The company accrues environmental liabilities when it is probable that obligations have been incurred and the amount can be reasonably estimated. Provisions for environmental liabilities are determined based on engineering estimated costs, taking into account the anticipated method and extent of remediation consistent with legal requirements, current technology and the possible use of the location. These provisions are not reduced by possible recoveries from third parties and projected cash expenditures are not discounted.

Foreign-currency translation
Monetary assets and liabilities in foreign currencies have been translated at the rates of exchange prevailing on December 31. Any exchange gains or losses are recognized in income.

Note 2. Business segments

The company operates its business in Canada, and its three reportable segments are Upstream, Downstream and Chemical. The factors used to identify these reportable segments are based on the nature of the operations that are undertaken by each segment, the structure of the company's internal organization, and reflect the nature of internal reviews by the company's Management Committee (MC). The MC is considered collectively, and not in their individual capacity, to be the company's Chief Operating Decision Maker (CODM), and includes the company's CEO, CFO, and a senior vice-president, who oversee the Upstream, Downstream and Chemical businesses. The Upstream segment is organized and operates to explore for and ultimately produce crude oil and its equivalent, and natural gas. The Downstream segment is organized and operates to refine crude oil into petroleum products and to distribute and market these products. The Chemical segment is organized and operates to manufacture and market hydrocarbon-based chemicals and chemical products. The above segmentation has been the long-standing practice of the company and is broadly understood across the petroleum and petrochemical industries.

Corporate and other includes assets and liabilities that do not specifically relate to business segments – primarily cash, capitalized interest costs, short-term borrowings, long-term debt and liabilities associated with incentive compensation, pension and other postretirement benefit liabilities. Net earnings effects under Corporate and other activities primarily include debt-related financing, corporate governance costs, non-service pension and postretirement benefit costs, share-based incentive compensation expenses and interest income.

The CODM generally allocates resources through an annual planning process. They also allocate capital based on detailed project economics and long-term strategic objectives across reportable segments. The CODM primarily uses changes in Net Income (loss) to assess segment financial performance.

Segment accounting policies are the same as those described in note 1, "Summary of significant accounting policies". Upstream, Downstream and Chemical expenses include amounts allocated from Corporate and other activities. The allocation is based on proportional segment expenses. Transfers of assets between segments are recorded at book amounts. Intersegment sales are made essentially at prevailing market prices. Assets and liabilities that are not identifiable by segment are allocated.

millions of Canadian dollars	Upstream 2025	Upstream 2024	Upstream 2023	Downstream (e) 2025	Downstream (e) 2024	Downstream (e) 2023	Chemical (e) 2025	Chemical (e) 2024	Chemical (e) 2023
Revenues and other income									
Revenues (a) (b)	**291**	121	222	**45,638**	50,114	49,241	**989**	1,124	1,239
Intersegment sales	**15,645**	17,868	16,274	**6,371**	6,771	6,509	**388**	323	342
Investment and other income (note 8)	**14**	26	16	**81**	59	108	**—**	2	—
Total revenues and other income	**15,950**	18,015	16,512	**52,090**	56,944	55,858	**1,377**	1,449	1,581
Expenses									
Exploration (note 15)	**7**	3	5	**—**	—	—	**—**	—	—
Purchases of crude oil and products	**6,263**	7,367	6,636	**45,017**	49,856	47,886	**923**	916	997
Production and manufacturing	**5,015**	4,644	4,917	**1,992**	1,741	1,702	**241**	197	260
Selling and general (note 11)	**—**	—	—	**725**	706	693	**81**	92	89
Federal excise tax and fuel charge	**—**	—	—	**1,710**	2,531	2,399	**5**	4	3
Depreciation and depletion (note 11)	**1,906**	1,747	1,680	**203**	181	183	**16**	15	15
Non-service pension and postretirement benefit	**—**	—	—	**—**	—	—	**—**	—	—
Financing (note 12)	**(14)**	4	7	**—**	—	—	**—**	—	—
Total expenses	**13,177**	13,765	13,245	**49,647**	55,015	52,863	**1,266**	1,224	1,364
Income (loss) before income taxes	**2,773**	4,250	3,267	**2,443**	1,929	2,995	**111**	225	217
Income tax expense (benefit) (note 3)	**652**	988	755	**574**	443	694	**29**	54	53
Net income (loss)	**2,121**	3,262	2,512	**1,869**	1,486	2,301	**82**	171	164
Cash flows from (used in) operating activities	**3,606**	4,664	3,100	**3,372**	1,049	608	**(28)**	211	53
Capital and exploration expenditures (c)	**1,480**	1,078	1,108	**412**	572	472	**11**	30	23
Property, plant and equipment									
Cost	**49,388**	47,920	46,776	**8,265**	7,887	7,368	**1,029**	1,015	1,018
Accumulated depreciation and depletion	**(23,351)**	(21,658)	(19,936)	**(4,602)**	(4,430)	(4,301)	**(758)**	(743)	(757)
Net property, plant and equipment (d) (f) (note 11)	**26,037**	26,262	26,840	**3,663**	3,457	3,067	**271**	272	261
Total assets	**29,111**	28,042	28,718	**11,036**	11,624	10,114	**540**	474	475

millions of Canadian dollars	Corporate and other 2025	Corporate and other 2024	Corporate and other 2023	Eliminations 2025	Eliminations 2024	Eliminations 2023	Consolidated 2025	Consolidated 2024	Consolidated 2023
Revenues and other income									
Revenues (a) (b)	**—**	—	—	**—**	—	—	**46,918**	51,359	50,702
Intersegment sales	**—**	—	—	**(22,404)**	(24,962)	(23,125)	**—**	—	—
Investment and other income (note 8)	**65**	86	143	**—**	—	—	**160**	173	267
Total revenues and other income	**65**	86	143	**(22,404)**	(24,962)	(23,125)	**47,078**	51,532	50,969
Expenses									
Exploration (note 15)	**—**	—	—	**—**	—	—	**7**	3	5
Purchases of crude oil and products	**—**	—	—	**(22,396)**	(24,955)	(23,120)	**29,807**	33,184	32,399
Production and manufacturing	**21**	17	—	**—**	—	—	**7,269**	6,599	6,879
Selling and general (note 11)	**588**	154	80	**(8)**	(7)	(5)	**1,386**	945	857
Federal excise tax and fuel charge	**—**	—	—	**—**	—	—	**1,715**	2,535	2,402
Depreciation and depletion (note 11)	**454**	40	29	**—**	—	—	**2,579**	1,983	1,907
Non-service pension and postretirement benefit	**41**	3	82	**—**	—	—	**41**	3	82
Financing (note 12)	**26**	37	62	**—**	—	—	**12**	41	69
Total expenses	**1,130**	251	253	**(22,404)**	(24,962)	(23,125)	**42,816**	45,293	44,600
Income (loss) before income taxes	**(1,065)**	(165)	(110)	**—**	—	—	**4,262**	6,239	6,369
Income tax expense (benefit) (note 3)	**(261)**	(36)	(22)	**—**	—	—	**994**	1,449	1,480
Net income (loss)	**(804)**	(129)	(88)	**—**	—	—	**3,268**	4,790	4,889
Cash flows from (used in) operating activities	**(282)**	69	(37)	**40**	(12)	10	**6,708**	5,981	3,734
Capital and exploration expenditures (c)	**124**	187	175	**—**	—	—	**2,027**	1,867	1,778
Property, plant and equipment									
Cost	**1,349**	1,226	1,038	**—**	—	—	**60,031**	58,048	56,200
Accumulated depreciation and depletion	**(457)**	(410)	(371)	**—**	—	—	**(29,168)**	(27,241)	(25,365)
Net property, plant and equipment (d) (f) (note 11)	**892**	816	667	**—**	—	—	**30,863**	30,807	30,835
Total assets	**3,658**	2,962	2,366	**(2,036)**	(164)	(474)	**42,309**	42,938	41,199

(a) Includes export sales to the United States of $9,223 million (2024 - $10,300 million, 2023 - $8,982 million).

(b) Revenues include both revenue within the scope of *ASC 606* and outside the scope of *ASC 606*. Trade receivables in "Accounts receivable - net" reported on the Consolidated balance sheet include both receivables within the scope of *ASC 606* and outside the scope of *ASC 606*. Revenue and receivables outside the scope of *ASC 606* primarily relate to physically settled commodity contracts accounted for as derivatives. Contractual terms, credit quality and type of customer are generally similar between contracts within the scope of *ASC 606* and those outside it.

Revenues

millions of Canadian dollars	2025	2024	2023
Revenue from contracts with customers	38,678	40,901	44,465
Revenue outside the scope of *ASC 606*	8,240	10,458	6,237
Total	46,918	51,359	50,702

(c) Capital and exploration expenditures (CAPEX) include exploration expenses, additions to property, plant and equipment, additions to finance leases, additional investments and acquisitions and the company's share of similar costs for equity companies. CAPEX excludes the purchase of carbon emission credits.

(d) Includes property, plant and equipment under construction of $3,467 million (2024 - $3,632 million, 2023 - $3,251 million).

(e) In 2025 and 2024, benzene and aromatic solvents are reported under the Downstream segment, whereas in 2023, they were reported under the Chemicals segment. The company has determined that the impact of this change is not material; therefore, the comparative periods have not been recast.

(f) In 2025, in conjunction with the company signing an agreement to sell the Calgary Imperial Campus, the Upstream segment transferred the asset to the Corporate and other segment for $466 million. The effects of this transaction have been eliminated for consolidation purposes. Prior periods have not been recast.

Note 3. Income taxes

In 2025, the company adopted the Financial Accounting Standards Board's ASU No. 2023-09, Improvements to Income Tax Disclosures on a retrospective basis in accordance with the transition provision.

millions of Canadian dollars	**2025**		2024		2023	
Current income tax expense (benefit)	**1,125**		1,586		1,556	
Deferred income tax expense (benefit)	**(131)**		(137)		(76)	
Total income tax expense (benefit)	**994**		1,449		1,480	
Federal	**625**		902		920	
Provincial	**369**		547		560	
Total income tax expense (benefit)	**994**		1,449		1,480	
Income (loss) before income taxes	**4,262**		6,239		6,369	
Canadian federal statutory tax rate	**639**	**15.0%**	935	15.0%	955	15.0%
Provincial (a)	**376**	**8.8%**	567	9.1%	582	9.1%
Increase (decrease) resulting from:						
Other	**(21)**	**(0.5%)**	(53)	(0.9%)	(57)	(0.9%)
Effective income tax rate	**994**	**23.3%**	1,449	23.2%	1,480	23.2%

(a) Provincial taxes in Alberta make up the majority (50 percent or more).

Deferred income taxes are based on differences between the accounting and tax values of assets and liabilities. These differences in value are re-measured at each year-end using the tax rates and tax laws expected to apply when those differences are realized or settled in the future. Components of deferred income tax liabilities and assets as at December 31 were:

millions of Canadian dollars	**2025**	2024	2023
Depreciation and amortization	**5,311**	5,267	5,366
Successful drilling and land acquisitions	**236**	236	237
Pension and benefits	**38**	(15)	(168)
Asset retirement obligation	**(858)**	(686)	(655)
Capitalized interest	**202**	185	155
LIFO inventory valuation	**(297)**	(468)	(406)
Tax loss carryforwards	**(65)**	(66)	(69)
Valuation allowance	**65**	66	69
Other	**(214)**	(35)	(60)
Net deferred income tax liabilities	**4,418**	4,484	4,469

The following table summarizes total income taxes (paid) refunded:

millions of Canadian dollars	**2025**	2024	2023
Federal	**(901)**	(1,119)	(2,562)
Provincial			
Alberta	**(342)**	(380)	(1,048)
Ontario	**(131)**	(176)	(343)
Other	**(61)**	(96)	(200)
Total income taxes (paid) refunded	**(1,435)**	(1,771)	(4,153)

Unrecognized tax benefits
Unrecognized tax benefits reflect the difference between positions taken or expected to be taken on income tax returns and the amounts recognized in the financial statements.

The following table summarizes the movement in unrecognized tax benefits:

millions of Canadian dollars	**2025**	2024	2023
Balance as of January 1	**34**	47	60
Additions based on current year's tax position	**6**	2	7
Additions for prior years' tax positions	**3**	—	—
Settlements with tax authorities	**(1)**	(15)	(20)
Balance as of December 31	**42**	34	47

The unrecognized tax benefit balances shown above predominantly relate to tax positions that would reduce the company's effective tax rate if the positions are favourably resolved. Unfavourable resolution of these tax positions generally would not increase the effective tax rate. The 2025, 2024 and 2023 changes in unrecognized tax benefits did not have a material effect on the company's net income or cash flow. The company's tax filings from 2020 to 2025 are subject to examination by the tax authorities. Tax filings from 2009 to 2024 have open objections and therefore are also subject to examination by the tax authorities. The Canada Revenue Agency has made certain adjustments to the company's filings. Management has evaluated these adjustments and is formally disputing those matters to which the company disagrees. The impact on unrecognized tax benefits and the company's effective income tax rate from these matters is not expected to be material.

Resolution of the related tax positions could take many years to complete. It is difficult to predict the timing of resolution for tax positions since such timing is not entirely within the control of the company.

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

Unrecognized tax benefits are not classified as future commitments because the company does not expect there will be any cash impact from the final settlements as sufficient funds have been deposited with the Canada Revenue Agency.

Note 4. Employee retirement benefits

Retirement benefits, which cover almost all retired employees and their surviving spouses, include pension income and certain health care and life insurance benefits. They are met through funded registered retirement plans and through unfunded supplementary benefits that are paid directly to recipients.

Pension income benefits consist mainly of company-paid defined benefit plans that are based on years of service and final average earnings. The company shares in the cost of health care and life insurance benefits. The company's benefit obligations are based on the projected benefit method of valuation that includes employee service to date and present compensation levels, as well as a projection of salaries to retirement.

The expense and obligations for both funded and unfunded benefits are determined in accordance with accepted actuarial practices and U.S. GAAP. The process for determining retirement-income expense and related obligations includes making certain long-term assumptions regarding the discount rate, rate of return on plan assets and rate of compensation increases. The obligation and pension expense can vary significantly with changes in the assumptions used to estimate the obligation and the expected return on plan assets.

The benefit obligations and plan assets associated with the company's defined benefit plans are measured on December 31.

	Pension benefits		Other postretirement benefits	
	2025	2024	**2025**	2024
Assumptions used to determine benefit obligations at December 31 (percent)				
Discount rate	**4.90**	4.70	**4.90**	4.70
Long-term rate of compensation increase	**4.00**	4.00	**4.00**	4.00

millions of Canadian dollars				
Change in benefit obligation				
Benefit obligation at January 1	**8,131**	8,154	**476**	581
Service cost	**186**	186	**4**	13
Interest cost	**369**	365	**22**	25
Actuarial loss (gain) (a)	**(247)**	(88)	**(43)**	(29)
Amendments and other	**19**	—	**1**	(78)
Benefits paid (b)	**(502)**	(486)	**5**	(36)
Benefit obligation at December 31	**7,956**	8,131	**465**	476
Accumulated benefit obligation at December 31	**7,225**	7,385		

(a) Actuarial loss (gain) primarily driven by changes in the year-end discount rate.
(b) Benefit payments for funded and unfunded plans.

The discount rate for the purpose of calculating year-end postretirement benefits plan obligation is determined by using the Canadian Institute of Actuaries recommended spot yield curve for high-quality, long-term Canadian corporate bonds with an average maturity (or duration) approximating that of the liabilities. For the measurement of the accumulated postretirement benefit obligation, the assumed health care cost trend rates start with 6.14 percent in 2026 and gradually decline to 3.57 percent by 2038 and beyond.

	Pension benefits		Other postretirement benefits	
millions of Canadian dollars	**2025**	2024	**2025**	2024
Change in plan assets				
Fair value at January 1	**8,553**	8,054		
Actual return (loss) gain	**345**	805		
Company contributions	**148**	150		
Benefits paid (a)	**(459)**	(452)		
Other	**(5)**	(4)		
Fair value at December 31	**8,582**	8,553		
Plan assets in excess of (less than) projected benefit obligation at December 31				
Funded plans	**1,035**	853		
Unfunded plans	**(409)**	(431)	**(465)**	(476)
Total (b)	**626**	422	**(465)**	(476)

(a) Benefit payments for funded plans only.
(b) Fair value of assets less projected benefit obligation shown above.

Funding of registered retirement plans complies with federal and provincial pension regulations, and the company makes contributions to the plans based on an independent actuarial valuation. In accordance with authoritative guidance relating to the accounting for defined pension and other postretirement benefits plans, the overfunded or underfunded status of the company's defined benefit postretirement plans was recorded as an asset or liability in the Consolidated balance sheet, and the changes in that funded status in the year in which the changes occurred was recognized through other comprehensive income.

	Pension benefits		Other postretirement benefits	
millions of Canadian dollars	**2025**	2024	**2025**	2024
Amounts recorded in the Consolidated balance sheet consist of:				
Other assets, including intangibles - net	**1,035**	853	**—**	—
Current liabilities	**(34)**	(33)	**(29)**	(28)
Other long-term obligations	**(375)**	(398)	**(436)**	(448)
Total recorded	**626**	422	**(465)**	(476)
Amounts recorded in accumulated other comprehensive income consist of:				
Net actuarial loss (gain)	**29**	237	**(145)**	(110)
Prior service cost	**346**	373	**(73)**	(78)
Total recorded in accumulated other comprehensive income, before-tax	**375**	610	**(218)**	(188)

The company establishes the long-term expected rate of return on plan assets by developing a forward-looking long-term return assumption for each asset class, taking into account factors such as the expected real return for the specific asset class and inflation. A single, long-term rate of return is then calculated as the weighted average of the target asset allocation percentages and the long-term return assumption for each asset class. The 2025 long-term expected return of 4.4 percent used in the calculations of pension expense compares to an actual rate of return of 4.5 percent and 5.6 percent over the last 10- and 20-year periods respectively, ending December 31, 2025.

	Pension benefits			Other postretirement benefits		
	2025	2024	2023	**2025**	2024	2023
Assumptions used to determine net periodic benefit cost for years ended December 31 (percent)						
Discount rate	**4.70**	4.60	5.10	**4.70**	4.60	5.10
Long-term rate of return on funded assets	**4.40**	5.60	4.80	**—**	—	—
Long-term rate of compensation increase	**4.00**	4.00	4.00	**4.00**	4.00	4.00

millions of Canadian dollars						
Components of net periodic benefit cost						
Service cost	**186**	186	162	**4**	13	12
Interest cost	**369**	365	373	**22**	25	28
Expected return on plan assets	**(395)**	(454)	(373)	**—**	—	—
Amortization of prior service cost	**27**	27	19	**(5)**	—	—
Amortization of actuarial loss (gain)	**11**	48	44	**(8)**	(8)	(9)
Net pension and other post retirement benefit enhancement	**19**	—	—	**1**	—	—
Net periodic benefit cost	**217**	172	225	**14**	30	31
Changes in amounts recorded in accumulated other comprehensive income						
Net actuarial loss (gain)	**(197)**	(439)	102	**(43)**	(29)	(14)
Amortization of net actuarial (loss) gain included in net periodic benefit cost	**(11)**	(48)	(44)	**8**	8	9
Prior service cost	**—**	—	184	**—**	(78)	—
Amortization of prior service cost included in net periodic benefit cost	**(27)**	(27)	(19)	**5**	—	—
Total recorded in other comprehensive income	**(235)**	(514)	223	**(30)**	(99)	(5)
Total recorded in net periodic benefit cost and other comprehensive income, before-tax	**(18)**	(342)	448	**(16)**	(69)	26

Costs for defined contribution plans, primarily the employee savings plan, were $47 million in 2025 (2024 - $47 million, 2023 - $44 million).

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

	Total pension and other postretirement benefits		
millions of Canadian dollars	**2025**	2024	2023
(Charge) credit to other comprehensive income, before-tax	**265**	613	(218)
Deferred income tax (charge) credit (note 17)	**(65)**	(150)	53
(Charge) credit to other comprehensive income, after-tax	**200**	463	(165)

The company's investment strategy for pension plan assets reflects a long-term view, a careful assessment of the risks inherent in plan assets and liabilities and broad diversification to reduce the risk of the portfolio. The pension plan assets are primarily invested in passive global equity and domestic fixed income index funds to diversify risk while minimizing costs. The fixed income funds are largely invested in investment-grade corporate and government debt securities with interest rate sensitivity designed to approximate the interest rate sensitivity of plan liabilities. The target asset allocation for the pension plan is reviewed periodically and set based on considerations such as risk, diversification, liquidity, and funding level. The target asset allocation for equity securities is 15 percent with the remainder in fixed-income securities.

The fair value measurement levels are accounting terms that refer to different methods of valuing assets. The terms do not represent the relative risk or credit quality of an investment.

The 2025 fair value of the pension plan assets, including the level within the fair value hierarchy, is shown in the table below:

		Fair value measurements at December 31, 2025, using:			
millions of Canadian dollars	Total	Level 1	Level 2	Level 3	Net Asset Value
Asset class					
Equity securities					
Canadian	**—**				**—**
Non-Canadian	**1,466**				**1,466**
Debt securities - Canadian					
Corporate	**1,693**				**1,693**
Government	**4,950**				**4,950**
Asset backed	**4**				**4**
Other	**45**				**45**
Equities – Venture capital	**167**				**167**
Real Estate	**207**				**207**
Cash	**50**	**18**			**32**
Total plan assets at fair value	**8,582**	**18**			**8,564**

The 2024 fair value of the pension plan assets, including the level within the fair value hierarchy, is shown in the table below:

		Fair value measurements at December 31, 2024, using:			
millions of Canadian dollars	Total	Level 1	Level 2	Level 3	Net Asset Value
Asset class					
Equity securities					
Canadian	—				—
Non-Canadian	2,584				2,584
Debt securities - Canadian					
Corporate	1,220				1,220
Government	4,400				4,400
Asset backed	4				4
Other	18				18
Equities – Venture capital	134				134
Real Estate	154				154
Cash	39	3			36
Total plan assets at fair value	8,553	3			8,550

A summary of pension plans with accumulated benefit obligation and projected benefit obligation in excess of plan assets is shown in the table below:

millions of Canadian dollars	Pension benefits	
	2025	2024
For unfunded pension plans covered by book reserves:		
Projected benefit obligation	**409**	431
Accumulated benefit obligation	**368**	386

(a) In 2025 and 2024, the fair value of plan assets exceeded the projected benefit obligation for both the company sponsored plan and its proportionate share of a joint venture sponsored plan.

Cash flows

Benefit payments expected in:

millions of Canadian dollars	Pension benefits	Other postretirement benefits
2026	**490**	**30**
2027	**490**	**30**
2028	**490**	**32**
2029	**490**	**32**
2030	**490**	**32**
2031 - 2035	**2,450**	**154**

In 2026, the company expects to make cash contributions of about $151 million to its pension plans.

Note 5. Other long-term obligations

millions of Canadian dollars	**2025**	2024
Employee retirement benefits (a) (note 4)	**811**	846
Asset retirement obligations and other environmental liabilities (b) (c)	**3,348**	2,641
Share-based incentive compensation liabilities (note 7)	**198**	119
Operating lease liability (note 13)	**149**	144
Restructuring liability (note 11)	**173**	—
Other obligations	**280**	120
Total other long-term obligations	**4,959**	3,870

(a) Total recorded employee retirement benefits obligations also included $63 million in current liabilities (2024 - $61 million).
(b) Total asset retirement obligations and other environmental liabilities also included $318 million in current liabilities (2024 - $291 million).
(c) For 2025, the asset retirement obligations were discounted at 6 percent (2024 - 6 percent). Asset retirement obligations incurred in the current period were level 3 fair value measurements.

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

millions of Canadian dollars	2025	2024	2023
Balance as at January 1	2,833	2,703	2,178
Additions (deductions)	721	96	471
Accretion	171	163	132
Settlement	(195)	(129)	(78)
Balance as at December 31	3,530	2,833	2,703

Estimated cash payments for asset retirement obligations are $241 million in 2026 and $227 million in 2027.

Note 6. Financial and derivative instruments

Financial instruments
The fair value of the company’s financial instruments is determined by reference to various market data and other appropriate valuation techniques. There are no material differences between the fair value of the company’s financial instruments and the recorded carrying value. At December 31, 2025 and December 31, 2024, the fair value of long-term debt ($3,447 million, excluding finance lease obligations) was primarily a level 2 measurement.

Derivative instruments
The company’s size, strong capital structure and the complementary nature of its business segments reduce the company’s enterprise-wide risk from changes in commodity prices, currency rates and interest rates. In addition, the company uses commodity-based contracts, including derivatives, to manage commodity price risk and to generate returns from trading. Commodity contracts held for trading purposes are presented in the Consolidated statement of income on a net basis in the line "Revenues" and in the Consolidated statement of cash flows in "Cash flows from (used in) operating activities". The company’s commodity derivatives are not accounted for under hedge accounting.

Credit risk associated with the company’s derivative position is mitigated by several factors, including the use of derivative clearing exchanges and the quality of and financial limits placed on derivative counterparties. The company maintains a system of controls that includes the authorization, reporting and monitoring of derivative activity.

At December 31, the net notional long/(short) position of derivative instruments was:

thousands of barrels	**2025**	2024
Crude	**954**	4,260
Products	**(702)**	(371)

Realized and unrealized gain or (loss) on derivative instruments recognized in the Consolidated statement of income is included in the following line on a before-tax basis:

millions of Canadian dollars	**2025**	2024	2023
Revenues	**41**	(69)	(5)

The estimated fair value of derivative instruments, and the related hierarchy level for the fair value measurement were as follows:

At December 31, 2025
millions of Canadian dollars

	Fair value						
	Level 1	Level 2	Level 3	Total	Effect of counterparty netting	Effect of collateral netting	Net carrying value
Assets							
Derivative assets (a)	**20**	**39**	**—**	**59**	**(18)**	**(2)**	**39**
Liabilities							
Derivative liabilities (b)	**18**	**14**	**—**	**32**	**(18)**	**—**	**14**

(a) Included in the Consolidated balance sheet line: "Materials, supplies and prepaid expenses", "Accounts receivable - net" and "Other assets, including intangibles - net".
(b) Included in the Consolidated balance sheet line: "Accounts payable and accrued liabilities" and "Other long-term obligations".

At December 31, 2024
millions of Canadian dollars

	Fair value				Effect of counterparty netting	Effect of collateral netting	Net carrying value
	Level 1	Level 2	Level 3	Total			
Assets							
Derivative assets (a)	38	21	—	59	(38)	—	21
Liabilities							
Derivative liabilities (b)	52	30	—	82	(38)	(14)	30

(a) Included in the Consolidated balance sheet line: "Materials, supplies and prepaid expenses", "Accounts receivable - net" and "Other assets, including intangibles - net".
(b) Included in the Consolidated balance sheet line: "Accounts payable and accrued liabilities" and "Other long-term obligations".

At December 31, 2025, and December 31, 2024, the company had $6 million and $22 million, respectively, of collateral under a master netting arrangement not offset against the derivatives on the Consolidated balance sheet in "Accounts receivable - net", primarily related to initial margin requirements.

Note 7. Share-based incentive compensation programs

Share-based incentive compensation programs are designed to retain selected employees, reward them for high performance and promote individual contribution to sustained improvement in the company's future business performance and shareholder value over the long-term. The nonemployee directors also participate in share-based incentive compensation programs.

Restricted stock units and deferred share units

Under the restricted stock unit plan, each unit entitles the recipient to the conditional right to receive from the company, upon vesting, an amount equal to the value of one common share of the company, based on the five-day average of the closing price of the company's common shares on the Toronto Stock Exchange on and immediately prior to the vesting dates. For the majority of the units, 50 percent of the units vest on the third anniversary of the grant date, and the remainder vest on the seventh anniversary of the grant date. Some management, professional, and technical participants will receive awards granted that vest 100 percent after three years. The company may also issue units to the chairman, president and chief executive officer where 50 percent of the units vest on the fifth anniversary of the grant date and the remainder vest on the tenth anniversary of the grant date, except that for awards granted prior to 2020, the vesting of the tenth anniversary portion is delayed until retirement if later than 10 years.

The deferred share unit plan is made available to nonemployee directors. The nonemployee directors can elect to receive all or part of their eligible directors' fees in units. The number of units granted is determined at the end of each calendar quarter by dividing the dollar amount of the nonemployee director's fees for that calendar quarter elected to be received as deferred share units by the average closing price of the company's shares for the five consecutive trading days ("average closing price") immediately prior to the last day of the calendar quarter. Additional units are granted to represent dividends on unexercised units, and are calculated by dividing the cash dividend payable on the company's shares by the average closing price immediately prior to the payment date for that dividend and multiplying the resulting number by the number of deferred share units held by the recipient, as adjusted for any share splits. Deferred share units cannot be exercised until after termination of service as a director, including termination due to death, and must be exercised in their entirety in one election no later than December 31 of the year following the year of termination of service. On the exercise date, the cash value to be received for the units is determined based on the company's average closing price immediately prior to the date of exercise, as adjusted for any share splits.

All units require settlement by cash payments with the following exceptions. The restricted stock unit program provides that, for units granted to Canadian residents, the recipient may receive one common share of the company per unit or elect to receive the cash payment for the units that vest on the seventh year anniversary of the grant date. For units where 50 percent vest on the fifth anniversary of the grant date and the remainder vest on the tenth anniversary of grant, the recipient may receive one common share of the company per unit or elect to receive cash payment for all that vest.

The company accounts for all units by using the fair-value-based method. The fair value of awards in the form of restricted stock and deferred share units is the market price of the company's stock. Under this method, compensation expense related to the units of these programs is measured each reporting period based on the company's current stock price and is recorded in the Consolidated statement of income over the requisite service period of each award.

The following table summarizes information about these units for the year ended December 31, 2025:

	Restricted stock units	Deferred share units
Outstanding at January 1, 2025	**4,223,070**	**44,706**
Granted	**918,900**	**6,393**
Vested/Exercised	**(717,310)**	**—**
Forfeited and cancelled	**(42,620)**	**—**
Outstanding at December 31, 2025	**4,382,040**	**51,099**

In 2025, the before-tax compensation expense charged against income for the restricted stock units and deferred share units was $212 million (2024 - $116 million, 2023 - $52 million). Income tax benefit recognized in income related to this compensation expense for the year was $51 million (2024 - $28 million, 2023 - $13 million). Cash payments of $107 million were made related to this compensation expense in 2025 (2024 - $74 million, 2023 - $68 million).

As of December 31, 2025, there was $251 million of total before-tax unrecognized compensation expense related to non-vested restricted stock units based on the company's share price at the end of the current reporting period. The weighted-average vesting period of non-vested restricted stock units is 4.2 years. All units under the deferred share programs have vested as of December 31, 2025.

Note 8. Investment and other income

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

millions of Canadian dollars	**2025**	2024	2023
Proceeds from asset sales	**101**	25	86
Book value of asset sales	**106**	7	13
Gain (loss) on asset sales, before-tax	**(5)**	18	73
Gain (loss) on asset sales, after-tax	**(9)**	16	63

Note 9. Litigation and other contingencies

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

Additionally, the company has other commitments arising in the normal course of business for operating and capital needs, all of which are expected to be fulfilled with no adverse consequences material to the company's operations, financial condition, or financial statements taken as a whole. Unconditional purchase obligations, as defined by accounting standards, are long-term commitments that are non-cancellable or cancellable only under certain conditions and that third parties have used to secure financing for the facilities that will provide the contracted goods and services. The company has not entered into any unconditional purchase obligations.

There were outstanding letters of credit aggregating to $668 million at December 31, 2025 (2024 - $475 million), issued as security for financial and performance conditions in relation to certain contracts and commitments. These letters of credit do not reduce any available funds under current borrowing arrangements.

As a result of the completed sale of the remaining company-owned Esso retail sites, the company was contingently liable at December 31, 2025, for guarantees relating to performance under contracts of other third-party obligations totalling $7 million (2024 - $10 million).

In the fourth quarter of 2025, the company recorded contractual obligations associated with the Norman Wells end of field life acceleration (see note 11, "Miscellaneous financial information").

Note 10. Common shares

At December 31 thousands of shares	**2025**	2024
Authorized	**1,100,000**	1,100,000
Outstanding	**483,593**	509,045

The most recent 12-month normal course issuer bid program came into effect June 29, 2025, under which Imperial continued its then-existing share purchase program. The program enabled the company to purchase up to a maximum of 25,452,248 common shares (5 percent of the total shares on June 15, 2025) which included shares purchased under the normal course issuer bid from Exxon Mobil Corporation. As in the past, Exxon Mobil Corporation advised the company that it intended to participate to maintain its ownership percentage at approximately 69.6 percent. The program completed on December 17, 2025 as a result of the company purchasing the maximum allowable number of shares under the program.

The excess of the purchase cost over the stated value of shares purchased has been recorded as a distribution of earnings reinvested.

The company's common share activities are summarized below:

	Thousands of shares	Millions of dollars
Balance as at January 1, 2023	584,153	1,079
Purchases at stated value	(48,316)	(87)
Balance as at December 31, 2023	535,837	992
Purchases at stated value	(26,792)	(50)
Balance as at December 31, 2024	509,045	942
Purchases at stated value	(25,452)	(47)
Balance as at December 31, 2025	**483,593**	**895**

The following table provides the calculation of basic and diluted earnings per common share and the dividends declared by the company on its outstanding common shares:

	2025	2024	2023
Net income (loss) per common share – basic			
Net income (loss) (millions of Canadian dollars)	**3,268**	4,790	4,889
Weighted-average number of common shares outstanding (millions of shares)	**502.8**	529.4	574.8
Net income (loss) per common share (dollars)	**6.50**	9.05	8.51
Net income (loss) per common share – diluted			
Net income (loss) (millions of Canadian dollars)	**3,268**	4,790	4,889
Weighted-average number of common shares outstanding (millions of shares)	**502.8**	529.4	574.8
Effect of employee share-based awards (millions of shares)	**1.2**	1.2	1.1
Weighted-average number of common shares outstanding, assuming dilution (millions of shares)	**504.0**	530.6	575.9
Net income (loss) per common share (dollars)	**6.48**	9.03	8.49
Dividends per common share – declared (dollars)	**2.88**	2.40	1.94

Note 11. Miscellaneous financial information

LIFO inventory
In 2025, net income included an after-tax gain of $61 million (2024 - $61 million gain, 2023 - $5 million gain) attributable to the effect of changes in last-in, first-out (LIFO) inventories. The replacement cost of inventories was estimated to exceed their LIFO carrying values at December 31, 2025 by about $1.5 billion (2024 - $2.0 billion). Inventories of crude oil and products at year-end consisted of the following:

millions of Canadian dollars	**2025**	2024
Crude oil	**1,067**	701
Petroleum products	**461**	513
Chemical products	**64**	57
Biofuels	**225**	40
Other	**394**	331
Total	**2,211**	1,642

Research and development
Research expenditures are mainly spent on developing technologies to improve bitumen recovery, reduce costs and reduce the environmental impact of upstream operations, including technologies to reduce greenhouse gas emissions intensity, supporting environmental and process improvements in the refineries, as well as accessing ExxonMobil's research worldwide.

The company has scientific research agreements with affiliates of ExxonMobil, 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.

Net research and development costs charged to expenses in 2025 were $134 million (2024 - $118 million, 2023 - $84 million). These costs are included in expenses due to the uncertainty of future benefits.

Accounts payable and accrued liabilities
"Accounts payable and accrued liabilities" included accrued taxes other than income taxes of $393 million at December 31, 2025 (2024 - $524 million), dividends payable of $350 million at December 31, 2025 (2024 - $307 million) and other miscellaneous current liabilities of $1,151 million at December 31, 2025 (2024 - $739 million).

Government assistance
ASC 832 "Government Assistance" requires disclosure of certain types of government assistance not otherwise covered by authoritative accounting guidance. The company receives allowances from governments in the form of emission credits as a result of performing better than facility level expectations for emission targets and records these at a nominal amount, generally in "Inventories of crude oil and products" on the Consolidated balance sheet. During 2024 and 2025, government assistance was immaterial to the company's financial results.

Restructuring charges
On September 29, 2025, the company announced restructuring plans to improve its performance by centralizing additional corporate and technical activities in global business and technology centres. The restructuring plans include a program of targeted workforce reductions. The program, which is expected to be substantially completed by the end of 2027, involves involuntary employee separations. In the third quarter of 2025, the company recorded charges of $330 million, before-tax, consisting primarily of restructuring costs associated with announced workforce reduction programs. These costs are captured in "Selling and general" on the Consolidated statement of income and reported in the Corporate and other segment.

The following table summarizes the reserves and charges related to the workforce reduction program, which are recorded in "Accounts payable and accrued liabilities" and "Other long-term obligations" on the Consolidated balance sheet.

millions of Canadian dollars	**2025**
Balance at January 1	—
Additions/adjustments	**330**
Payments made	—
Balance at December 31	**330**

Calgary Imperial Campus
In the third quarter of 2025, the Corporate and other segment included a non-cash impairment charge of $406 million, before-tax, in conjunction with the company signing an agreement to sell the Calgary Imperial Campus. The impairment was reflected in "Depreciation and depletion (includes impairments)" on the Consolidated statement of income and in "Property, plant and equipment, less accumulated depreciation and depletion" on the Consolidated balance sheet. The transaction closed in the fourth quarter of 2025.

Norman Wells
In the fourth quarter of 2025, the company accelerated the end of field life of the Norman Wells asset, resulting in a $421 million expense, before-tax, reported in the Upstream segment. The expense consisted of a non-cash impairment charge of $142 million, reflected in "Depreciation and depletion (includes impairments)" on the Consolidated statement of income and in "Property, plant and equipment, less accumulated depreciation and depletion" on the Consolidated balance sheet, and a one-time charge of $279 million related to contractual obligations associated with the end of field life acceleration, reflected in "Production and manufacturing" on the Consolidated statement of income.

Note 12. Financing and additional notes and loans payable information

millions of Canadian dollars	**2025**	2024	2023
Debt-related interest (a)	**131**	192	203
Capitalized interest	**(105)**	(155)	(141)
Net interest expense	**26**	37	62
Other interest	**(14)**	4	7
Total financing	**12**	41	69

(a) Includes related party interest with ExxonMobil.

During the fourth quarter of 2025, the company extended the maturity dates of its two existing $250 million committed lines of credit to November 2026 and November 2027, respectively.

The company has not drawn on any of its outstanding $500 million of available credit facilities.

At December 31, 2025 and at December 31, 2024, the company had no short-term borrowings outstanding.

Note 13. Leases

The company generally purchases the property, plant and equipment used in operations, but there are situations where assets are leased, primarily storage tanks, rail cars, marine vessels, and transportation and other facilities. Right of use assets and lease liabilities are established on the balance sheet for leases with an expected term greater than one year, by discounting the amounts fixed in the lease agreement for the duration of the lease which is reasonably certain, considering the probability of exercising any early termination and extension options. The portion of the fixed payment related to service costs for tankers and finance leases is excluded from the calculation of right of use assets and lease liabilities. Usually, assets are leased only for a portion of their useful lives and are accounted for as operating leases. In limited situations, assets are leased for nearly all of their useful lives and are accounted for as finance leases. In general, leases are capitalized using the company's incremental borrowing rate.

Variable payments under these lease agreements are not significant. Residual value guarantees, restrictions, or covenants related to leases, and transactions with related parties are also not significant. The company's activities as a lessor are not material.

The table below summarizes the total lease cost incurred:

	2025		2024		2023	
millions of Canadian dollars	Operating leases	Finance leases	Operating leases	Finance leases	Operating leases	Finance leases
Operating lease cost	**105**		111		114	
Short-term and other (net of sublease rental income)	**108**		50		30	
Amortization of right of use assets		**16**		16		19
Interest on lease liabilities		**27**		28		29
Total lease cost	**213**	**43**	161	44	144	48

The following table summarizes the amounts related to operating leases and finance leases recorded on the Consolidated balance sheet, weighted-average remaining lease term and weighted-average discount rates applied at December 31:

	2025		2024	
millions of Canadian dollars	Operating leases	Finance leases	Operating leases	Finance leases
Right of use assets				
Included in Other assets, including intangibles - net	**285**		240	
Included in Property, plant and equipment, less accumulated depreciation and depletion		**582**		579
Total right of use assets	**285**	**582**	240	579
Lease liability due within one year				
Included in Accounts payable and accrued liabilities	**87**	**—**	100	—
Included in Notes and loans payable		**19**		18
Long-term lease liability				
Included in Other long-term obligations	**149**	**—**	144	—
Included in Long-term debt		**531**		545
Total lease liability	**236**	**550**	244	563
Weighted-average remaining lease term (years)	**5**	**35**	5	35
Weighted-average discount rate (percent)	**3.2**	**5.8**	4.1	4.8

The maturity analysis of the company's lease liabilities as at December 31 are summarized below:

	2025	
millions of Canadian dollars	Operating leases	Finance leases
Maturity analysis of lease liabilities		
2026	**93**	**49**
2027	**44**	**48**
2028	**39**	**47**
2029	**31**	**45**
2030	**16**	**44**
2031 and beyond	**29**	**862**
Total lease payments	**252**	**1,095**
Discount to present value	**(16)**	**(545)**
Total lease liability	**236**	**550**

In addition to the operating lease liabilities in the table immediately above, at December 31, 2025, there were no additional undiscounted commitments for leases not yet commenced (2024 - $56 million).

There are no estimated cash payments for operating and finance leases not yet commenced in 2026 and 2027.

The table below summarizes the cash paid for amounts included in the measurement of lease liabilities and the right of use assets obtained in exchange for new lease liabilities:

	2025		2024		2023	
millions of Canadian dollars	Operating leases	Finance leases	Operating leases	Finance leases	Operating leases	Finance leases
Cash paid for amounts included in the measurement of lease liabilities						
Cash flows from operating activities	**121**	**—**	118	—	56	—
Cash flows from financing activities		**18**		22		22
Non-cash right of use assets recorded for lease liabilities						
In exchange for lease liabilities during the year	**107**	**17**	152	—	61	—

Note 14. Long-term debt

At December 31 millions of Canadian dollars	**2025**	2024
Long-term debt (a) (b)	**3,447**	3,447
Finance leases (c)	**531**	545
Total long-term debt	**3,978**	3,992

(a) Borrowed under an existing agreement with an affiliated company of ExxonMobil that provides for a long-term, variable-rate, Canadian dollar loan from ExxonMobil to the company of up to $7.75 billion at interest equivalent to Canadian market rates. The agreement is effective until June 30, 2035, cancellable if ExxonMobil provides at least 370 days advance written notice.

(b) The weighted-average interest rate on long-term borrowings outstanding with ExxonMobil, at December 31, 2025 was 2.7 percent (2024 - 3.9 percent).

(c) Finance leases are primarily associated with transportation facilities and services agreements. The average imputed interest rate was 5.8 percent in 2025 (2024 - 4.8 percent). Total finance lease obligations also include $19 million in current liabilities (2024 - $18 million). Principal payments on finance leases of approximately $17 million on average per year are due in each of the next four years after December 31, 2026.

Note 15. Accounting for suspended exploratory well costs

The company continues capitalization of exploratory well costs when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the company is making sufficient progress assessing the reserves and the economic and operating viability of the project. The term “project” as used in this report can refer to a variety of different activities and does not necessarily have the same meaning as in any government payment transparency reports. The company had no capitalized suspended exploratory well costs as at December 31, 2025, 2024 and 2023.

Exploration activity involves drilling multiple wells, over a number of years, to fully evaluate a project. The company had no projects with exploratory wells costs capitalized as at December 31, 2025, 2024 and 2023.

Note 16. Transactions with related parties

Revenues and expenses of the company also include the results of transactions with affiliated companies of ExxonMobil in the normal course of operations. These were conducted on terms comparable to those which would have been conducted with unrelated parties and primarily consisted of the purchase and sale of crude oil, natural gas, petroleum and chemical products, as well as technical, engineering and research and development costs. Transactions with ExxonMobil also included amounts paid and received in connection with the company's participation in a number of upstream activities conducted jointly in Canada.

In addition, the company has existing agreements with ExxonMobil:

a) To provide services to the company and to share common business and operational support services that allow the companies to consolidate duplicate work and systems;

b) To operate certain western Canada production properties owned by ExxonMobil, as well as provide for the delivery of management, business and technical services to ExxonMobil in Canada. These agreements are designed to provide organizational efficiencies and to reduce costs. No separate legal entities were created from these arrangements. Separate books of account continue to be maintained for the company and ExxonMobil. The company and ExxonMobil retain ownership of their respective assets, and there is no impact on operations or reserves;

c) To provide for the option of equal participation in new upstream opportunities; and

d) To enter into derivative agreements on each other's behalf.

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

Related party revenues and purchases in 2025 were $13,534 million and $5,369 million, respectively. Related party revenues and purchases in 2024 have been revised from $11,725 million to $14,654 million and from $3,722 million to $6,651 million, respectively. Related party revenues and purchases in 2023 have been revised from $13,544 million to $16,166 million and from $4,125 million to $6,747 million, respectively. Impacts of the revision offset to zero.

- Related party revenues and purchases with ExxonMobil in 2025 were $13,534 million and $5,227 million, respectively. Related party revenues and purchases with ExxonMobil in 2024 have been revised from $11,725 million to $14,654 million and from $3,617 million to $6,546 million, respectively. Related party revenues and purchases with ExxonMobil in 2023 have been revised from $13,544 million to $16,166 million and from $4,026 million to $6,648 million, respectively. Impacts of the revision offset to zero.

As at December 31, 2025, the company had an outstanding long-term loan of $3,447 million (2024 - $3,447 million) from ExxonMobil (see note 14, "Long-term debt", and note 12, "Financing and additional notes and loans payable information" for further details). The amount of financing costs with ExxonMobil in 2025 were $97 million (2024 - $161 million).

Imperial has other related party transactions not detailed above in note 16, as they are not significant.

Note 17. Other comprehensive income (loss) information

Changes in accumulated other comprehensive income (loss):

millions of Canadian dollars	**2025**	2024	2023
Balance at January 1	**(214)**	(677)	(512)
Postretirement benefits liability adjustment:			
Current period change excluding amounts reclassified from accumulated other comprehensive income	**181**	412	(206)
Amounts reclassified from accumulated other comprehensive income	**19**	51	41
Balance at December 31	**(14)**	(214)	(677)

Amounts reclassified out of accumulated other comprehensive income (loss) - before-tax income (expense):

millions of Canadian dollars	**2025**	2024	2023
Amortization of postretirement benefits liability adjustment included in net benefit cost (a)	**(25)**	(67)	(54)

(a) This accumulated other comprehensive income component is included in the computation of net periodic benefit cost (note 4).

Income tax expense (credit) for components of other comprehensive income (loss):

millions of Canadian dollars	**2025**	2024	2023
Postretirement benefits liability adjustments:			
Postretirement benefits liability adjustment (excluding amortization)	**59**	134	(66)
Amortization of postretirement benefits liability adjustment included in net benefit cost	**6**	16	13
Total	**65**	150	(53)

Supplemental information on oil and gas exploration and production activities (unaudited)

The information on pages 66 to 67 excludes items not related to oil and natural gas extraction, such as administrative and general expenses, pipeline operations, gas plant processing fees and gains or losses on asset sales. The company's 25 percent interest in proved synthetic crude oil reserves in the Syncrude joint venture is included as part of the company's total proved oil and gas reserves and in the calculation of the standardized measure of discounted future cash flows, in accordance with U.S. Securities and Exchange Commission (SEC) and U.S. Financial Accounting Standards Board rules. Results of operations, costs incurred in property acquisitions, exploration and development activities, and capitalized costs include the company's share of Kearl, Syncrude and other unproved mineable acreages in the following tables.

Results of operations

millions of Canadian dollars	**2025**	2024	2023
Revenue			
Sales to third parties (a)	**6,509**	7,171	6,420
Transfers (a) (b)	**3,010**	3,337	3,220
	9,519	10,508	9,640
Production expenses	**4,828**	4,769	5,015
Exploration expenses	**7**	3	5
Depreciation and depletion	**1,697**	1,539	1,475
Income taxes	**714**	974	733
Results of operations	**2,273**	3,223	2,412

(a) Sales to third parties or transfers do not include the sale of natural gas and natural gas liquids purchased for resale, as well as royalty payments or diluent costs. These items are reported gross in note 2 in "Revenues", "Intersegment sales" and in "Purchases of crude oil and products".

(b) Sales of crude oil to consolidated affiliates are at market value, using posted field prices. Sales of natural gas liquids to consolidated affiliates are at prices estimated to be obtainable in a competitive, arm's-length transaction.

The amounts reported as costs incurred in property acquisitions, exploration and development activities include both capitalized costs and costs charged to expense during the year. Costs incurred also include new asset retirement obligations established in the current year, as well as increases or decreases to the asset retirement obligation resulting from changes in cost estimates or abandonment date.

Costs incurred in property acquisitions, exploration and development activities

millions of Canadian dollars	**2025**	2024	2023
Property costs (a)			
Proved	**—**	—	—
Unproved	**—**	—	—
Exploration costs	**7**	3	5
Development costs	**2,178**	1,171	1,580
Total costs incurred in property acquisitions, exploration and development activities	**2,185**	1,174	1,585

(a) "Property costs" are payments for rights to explore for petroleum and natural gas and for purchased reserves (acquired tangible and intangible assets such as gas plants, production facilities and producing-well costs are included under "producing assets"). "Proved" represents areas where successful drilling has delineated a field capable of production. "Unproved" represents all other areas.

Capitalized costs

millions of Canadian dollars	**2025**	2024
Property costs (a)		
Proved	**1,839**	1,840
Unproved	**492**	492
Producing assets	**42,789**	41,034
Incomplete construction	**2,872**	2,555
Total capitalized cost	**47,992**	45,921
Accumulated depreciation and depletion	**(23,032)**	(21,247)
Net capitalized costs	**24,960**	24,674

(a) "Property costs" are payments for rights to explore for petroleum and natural gas and for purchased reserves (acquired tangible and intangible assets such as gas plants, production facilities and producing-well costs are included under "producing assets"). "Proved" represents areas where successful drilling has delineated a field capable of production. "Unproved" represents all other areas.

Standardized measure of discounted future cash flows

As required by the U.S. Financial Accounting Standards Board, the standardized measure of discounted future net cash flows is computed by applying first-day-of-the-month average prices, year-end costs and legislated tax rates, and a discount factor of 10 percent to net proved reserves. The standardized measure includes costs for future dismantlement, abandonment and remediation obligations. The company believes the standardized measure does not provide a reliable estimate of the company's expected future cash flows to be obtained from the development and production of its oil and gas properties or of the value of its proved oil and gas reserves. The standardized measure is prepared on the basis of certain prescribed assumptions, including first-day-of-the-month average prices, which represent discrete points in time and therefore may cause significant variability in cash flows from year to year as prices change.

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

millions of Canadian dollars	**2025**	2024	2023
Future cash flows	**142,478**	158,677	158,347
Future production costs	**(79,939)**	(88,061)	(101,640)
Future development costs	**(24,960)**	(24,792)	(24,074)
Future income taxes	**(8,319)**	(10,196)	(7,016)
Future net cash flows	**29,260**	35,628	25,617
Annual discount of 10 percent for estimated timing of cash flows	**(13,910)**	(17,461)	(11,615)
Discounted future cash flows	**15,350**	18,167	14,002

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

millions of Canadian dollars	**2025**	2024	2023
Balance at beginning of year	**18,167**	14,002	25,554
Changes resulting from:			
Sales and transfers of oil and gas produced, net of production costs	**(4,775)**	(6,041)	(4,918)
Net changes in prices, development costs and production costs (a)	**(3,616)**	7,134	(16,908)
Extensions, discoveries, additions and improved recovery, less related costs	**—**	—	58
Development costs incurred during the year	**1,642**	1,191	1,182
Revisions of previous quantity estimates	**1,085**	1,788	2,146
Accretion of discount	**1,868**	1,485	2,535
Net change in income taxes	**979**	(1,392)	4,353
Net change	**(2,817)**	4,165	(11,552)
Balance at end of year	**15,350**	18,167	14,002

(a) SEC rules require the company's reserves to be calculated on the basis of average first-day-of-the-month oil and natural gas prices during the reporting year. Future net cash flows are determined based on the net proved reserves as outlined in the "Net proved reserves table".

Net proved reserves (a)

	Liquids (b)	Natural gas	Synthetic crude oil	Bitumen	Total oil-equivalent basis (c)
	millions of barrels	billions of cubic feet	millions of barrels	millions of barrels	millions of barrels
Beginning of year 2023	4	72	353	1,824	2,193
Revisions	(2)	2	26	90	114
Improved recovery	—	—	—	—	—
(Sale) purchase of reserves in place	—	(1)	—	—	—
Discoveries and extensions	—	—	—	—	—
Production	(2)	(12)	(25)	(103)	(132)
End of year 2023	—	61	354	1,811	2,175
Revisions	2	3	(35)	114	82
Improved recovery	—	—	—	—	—
(Sale) purchase of reserves in place	—	—	—	—	—
Discoveries and extensions	—	—	—	—	—
Production	(2)	(11)	(23)	(109)	(136)
End of year 2024	—	53	296	1,816	2,121
Revisions	2	7	17	37	57
Improved recovery	—	—	—	—	—
(Sale) purchase of reserves in place	—	—	—	—	—
Discoveries and extensions	—	—	—	—	—
Production	(2)	(11)	(25)	(113)	(142)
End of year 2025	**—**	**49**	**288**	**1,740**	**2,036**
Net proved developed reserves included above, as of					
January 1, 2023	4	60	248	1,691	1,953
December 31, 2023	—	53	242	1,706	1,957
December 31, 2024	—	41	190	1,697	1,894
December 31, 2025	**—**	**41**	**288**	**1,641**	**1,936**
Net proved undeveloped reserves included above, as of					
January 1, 2023	—	12	105	133	240
December 31, 2023	—	8	112	105	218
December 31, 2024	—	12	106	119	227
December 31, 2025	**—**	**8**	**—**	**99**	**100**

(a) Net reserves are the company's share of reserves after deducting the shares of mineral owners or governments or both. All reported reserves are located in Canada. Reserves of natural gas are calculated at a pressure of 14.73 pounds per square inch at 60°F.
(b) Liquids include crude oil and natural gas liquids (NGLs). NGL proved reserves are not material and are therefore included under liquids.
(c) Gas converted to oil-equivalent at six million cubic feet per one thousand barrels.

The information above describes changes during the years and balances of proved oil and gas reserves at year-end 2023, 2024 and 2025. The definitions used are in accordance with the SEC Rule 4-10 (a) of Regulation S-X.

Proved oil and natural gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations – prior to the time at which contracts providing the right to operate expire. In some cases, substantial new investments in additional wells and other facilities will be required to recover these proved reserves.

In accordance with SEC rules, the year-end reserves volumes, as well as the reserves change categories shown in the proved reserves tables are required to be calculated on the basis of average prices during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period. These reserves quantities were also used in calculating unit-of-production depreciation rates and in calculating the standardized measure of discounted net cash flow.

Revisions in previously estimated volumes of proved reserves for existing fields can occur due to the evaluation or re-evaluation of already available geologic, reservoir or production data; new geologic, reservoir or production data; or changes in the average of first-day-of-the-month oil and natural gas prices and/or costs that are used in the estimation of reserves. Revisions can also result from significant changes in either development strategy or production equipment and facility capacity.

In 2023, upward revisions of proved bitumen of 0.1 billion barrels were driven by lower royalty obligations associated with lower pricing and minor technical revisions at Cold Lake and Kearl. A slight increase in proved reserves for synthetic crude oil is associated with lower royalty obligations associated with pricing. Conventional proved liquids reserves decreased to zero under existing pricing and operating conditions.

In 2024, upward revisions of proved bitumen of 0.1 billion barrels were primarily driven by updates to the Kearl geological model, Kearl well density, and Cold Lake infill drilling, partially offset by reductions associated with higher royalty obligations and Kearl pit limit updates. A decrease to synthetic oil proved reserves is associated with regulatory approval for ore sterilization at Syncrude.

In 2025, upward revisions of proved bitumen were primarily driven by steam scheduling, development drilling, LASER process at Cold Lake and lower royalty obligations associated with pricing for both Kearl and Cold Lake. An increase in proved reserves for synthetic crude oil is associated with lower royalty obligation.

Under the terms of certain contractual arrangements or government royalty regimes, lower prices can also increase proved reserves attributable to the company. The company’s operating decisions and its outlook for future production volumes are not impacted by proved reserves as disclosed under the SEC definition.

Net proved reserves are determined by deducting the estimated future share of mineral owners or governments or both. For liquids and natural gas, net proved reserves are based on estimated future royalty rates as of the date the estimate is made incorporating the applicable governments’ oil and gas royalty regimes. For bitumen, net proved reserves are based on the company’s best estimate of average royalty rates over the remaining life of each of the Cold Lake and Kearl fields, and they incorporate the Alberta government’s oil sands royalty regime. For synthetic crude oil, net proved reserves are based on the company’s best estimate of average royalty rates over the remaining life of the project, and they incorporate the Alberta government’s oil sands royalty regime. In all cases, actual future royalty rates may vary with production, price and costs.

Net proved developed reserves are those volumes that are expected to be recovered through existing wells, facilities, or mining activities with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well or facility. Net proved undeveloped reserves are those volumes that are expected to be recovered as a result of future investments to drill new wells, to recomplete existing wells and/or to install facilities to collect and deliver the production from existing and future wells, facilities, or mining activities.

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