



Shell plc
Annual Report and Accounts
For the year ended December 31, 2025

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Terms and abbreviations

Currencies

\$	US dollar
€	euro
£	sterling

Units of measurement

acre	approximately 0.004 square kilometres
b(/d)	barrels (per day)
bbl	barrel
boe(/d)	barrels of oil equivalent (per day); natural gas volumes are converted into oil equivalent using a factor of 5,800 scf per barrel
GJ	gigajoule
GW	gigawatt
kboe(/d)	thousand barrels of oil equivalent (per day); natural gas volumes are converted into oil equivalent using a factor of 5,800 scf per barrel
kWh	kilowatt-hours
mb/d	million barrels per day
megajoule	a unit of energy equal to one million joules
MMBtu	million British thermal units
mtpa	million tonnes per annum
MW	megawatt
MWh	megawatt-hours
Nm3	normal cubic metre
per day	volumes are converted into a daily basis using a calendar year
scf(/d)	standard cubic feet (per day)
TWh	terawatt-hours

Products

GTL	gas-to-liquids
LNG	liquefied natural gas
LPG	liquefied petroleum gas
NGL	natural gas liquids

Miscellaneous

Act	UK Companies Act 2006
ADS	American Depositary Share
AGM	Annual General Meeting
API	American Petroleum Institute
APM	Alternative performance measure
ARC	Audit and Risk Committee
CAGR	compound annual growth rate
CCS	carbon capture and storage
CCS earnings	earnings on a current cost of supplies basis
CFFO	cash flow from operating activities
CISO	Chief Information Security Officer
CMD	Capital Markets Day
CMF	carbon management framework
CO ₂	carbon dioxide
CO ₂ e	carbon dioxide equivalent
CRC	Carbon Reporting Committee
CSRD	Corporate Sustainability Reporting Directive
DE&I	Diversity, equity, and inclusion

EBITDA	Earnings Before Interest Taxes Depreciation and Amortization
EC	Executive Committee
EMTN	Euro medium-term note
EPS	earnings per share
ESRS	European Sustainability Reporting Standards
ETS24	Energy Transition Strategy 2024
EV	Electric vehicle
FPI	Fatality and Permanent Impairments
FCF	free cash flow
FID	final investment decision
GAAP	generally accepted accounting principles
GHG	greenhouse gas
HSSE	health, safety, security and environment
IAS	International Accounting Standards
IEA	International Energy Agency
IFRS	International Financial Reporting Standard(s)
IOGP	International Association of Oil & Gas Producers
IPCC	Intergovernmental Panel on Climate Change
Ipieca	International Petroleum Industry Environmental Conservation Association
ISSB	International Sustainability Standards Board
KPI	Key performance indicator
LGBT+	Lesbian, gay, bisexual and transgender
LTIP	Long-term Incentive Plan
NBS	Nature-Based Solutions
NCI	net carbon intensity
NGO	Non-governmental organisation
NOMCO	Nomination and Succession Committee
NOV	Non-operated venture
NZE	Net zero emissions
OECD	Organisation for Economic Co-operation and Development
OML	oil mining lease
OP 25	Operating Plan 2025
OPEC	Organization of the Petroleum Exporting Countries
OPEC+	12 members of the OPEC and 11 other non-OPEC members
OPL	oil prospecting licence
PSC	production-sharing contract
PSP	Performance Share Plan
R&D	Research and development
REMCO	Remuneration Committee
RNG	Renewable natural gas
RT	real terms
SEAM	Safety, Environment and Asset Management
SEC	US Securities and Exchange Commission
SGBP	Shell General Business Principles
SIAI	Shell Internal Audit and Investigations
SP	social performance
SUSCO	Sustainability Committee
TCFD	Task Force on Climate-related Financial Disclosures
TSR	total shareholder return
WACC	weighted average cost of capital
T	Indicates information that supports TCFD disclosure

Strategic Report

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Chair's message



Shell provides energy, directly or indirectly, to around a billion people every year. That number speaks not only to our reach, but also our role in connecting people with the energy they need.

As Chief Executive Officer, Wael Sawan has continued to embed a focus on performance, discipline and simplification across Shell. This has translated into stronger operational performance, greater discipline in capital allocation, and more clarity about where we create value.

This approach has supported attractive shareholder returns: in the three years to the end of 2025, we have outperformed our peers in terms of total shareholder return [A]. In 2025, we distributed 52% of cash flow from operations to shareholders through our dividends and share buybacks, as we continue to grow value per share.

Today, Shell continues to become more competitive and resilient – and better positioned to create value and help provide the energy people need in a world that has become more fragmented and complex.

Our changing world

A renewed focus on energy security has brought with it a broader recognition that oil and gas will still represent a significant part of the global energy system for decades to come. At Shell, we continue to invest in helping to provide secure supplies of energy with projects like Orca in Brazil, formerly called Gato do Mato, and our multiple production hubs in the Gulf of America.

[A] See page 188 in the "Annual Report on Remuneration" for more information.

Our task is to manage oil and gas production responsibly and competitively, with a focus on reducing the emissions from our operations. We also believe that gas, including LNG, can play a vital role through the energy transition – as a flexible and reliable lower-carbon alternative to coal in power generation and industry, as a solution for heavy-duty transport and shipping, and as a complement to renewables, helping balance grids as wind and solar scale.

June 2025 saw the first cargo from the new LNG Canada facility. It was a proud moment for Shell and our partners, not only because of its significant technical achievements, but because it was designed to be among the lowest carbon intensity LNG facilities in the world – with many cargoes going to meet growing energy demand in Asia.

At the same time, climate change remains a real challenge. We have a target to become a net-zero emissions energy business by 2050, and we are committed to playing our part in helping to decarbonise the global energy system.

Low-carbon energy options are advancing on multiple tracks. Technologies such as wind and solar are now well established, while others – including biofuels like sustainable aviation fuel, renewable hydrogen and carbon capture and storage (CCS) – will be best able to scale if policy frameworks develop, markets evolve and demand builds.

Even as the energy mix changes, overall demand continues to grow. Moving from a global energy system built on coal, oil and gas to one that is increasingly electrified means redesigning the infrastructure that underpins modern life. We must change how we power industry, heat homes, move people and goods, build cities and balance grids.

Despite these challenging objectives, there is progress to point to. In October, I visited China where I saw the pace of electrification for myself. I met Shell colleagues and partners engaged in that effort, scaling up electric vehicle infrastructure and working alongside many of China's leading industrial players.

Taken together, these developments illustrate an energy transition that is under way, but far from uniform. Countries are advancing from very different starting points, shaped by their resources, infrastructure and energy needs. Even as energy systems change, global economic growth depends on supply that is available, reliable and delivered at scale.

Our role in the energy transition

In this context, Shell's Board has a clear fiduciary responsibility to promote the long-term success of the company, including through competitive returns to our shareholders. For Shell, fulfilling that responsibility means pursuing investments that help us outperform the competition and increase returns – all within the reality that there is only a finite pool of money investors are willing to commit to the energy system.

As a result, Shell maintains flexibility across emerging technologies so that if conditions strengthen and markets mature, we are well positioned to compete. We focus on where we can make a difference at scale, where we have competitive advantage, and where we can deliver value for our shareholders. It was through this lens that we took the decision in September 2025 not to restart construction of our planned biofuels plant in Rotterdam.

We have also seen what is possible when the right conditions come together. In August 2025, we marked the first injection of CO₂ at the Northern Lights project in Norway – Europe's flagship cross-border carbon transport and storage development and a milestone many years in the making. It shows what can be achieved when governments provide stable policy frameworks, industry brings world-class engineering and investment, and customer demand is aligned.

At our Capital Markets Day 2023, we said we would invest \$10–15 billion in low-carbon energy solutions between 2023 and 2025, which we have delivered on. In 2025, we also spent almost \$500 million on research and development projects that aim to contribute to decarbonisation, representing about 41% of our total research and development expenditure.

Shell began life as a trading company more than a century ago. Visiting Trading and Supply colleagues in Rotterdam in December, it was great to see how we are using that capability to deliver biofuels and power, as well as oil and gas. Trading is not simply one activity within Shell; it sits at the heart of our integrated model.

Our culture

That ability to operate as a truly integrated global organisation is one of Shell's defining strengths today – and will matter even more in the years ahead. But integration ultimately depends on people, and as I visited colleagues around the globe in 2025 – from our Board offsite in Australia to meeting colleagues in China and the Netherlands – I saw the operational excellence of our people in action.

Being a global business – with a workforce that spans continents – makes us naturally diverse. We remain committed to being a place where everyone feels valued and respected, wherever they are. Employee engagement has remained steady – a reflection of both the scale of change and the resilience of our people – and we recognise there is more to do to strengthen connection, build trust, and ensure our colleagues feel part of Shell's ongoing transformation through 2026 and beyond.

Our confidence

In 2026, we expect energy demand to keep growing, the pace of the transition to remain uncertain – and signals from governments, markets and customers may not always align. But I am confident in Shell's ability to thrive because of the steps our people have taken to embed performance, discipline and simplification. These principles have made our organisation more competitive and resilient.

Shell enters 2026 as a leaner, stronger and more confident organisation. That confidence does not come from assuming the world will become easier. It comes from the culture our people bring to life every day and the foundations that position Shell to navigate the years ahead and deliver more value with less emissions in a changing energy system.

Sir Andrew Mackenzie
Chair



1. Board and Executive Committee visit, Australia, 2025.
2. LNG tanker, Canada, 2025.
3. Mars platform with Olympus in the distance, Gulf of America, 2025.



Chief Executive Officer's review



We are in a world defined by more uncertainty – from increasingly fragmented geopolitics, to the rapid rise of artificial intelligence and the pressures of climate change. Energy sits at the heart of this changing world, highlighting the critical role of our sector.

As I write this message, amid the turmoil of the conflict in the Middle East, we feel that critical role more than ever. We are focusing first and foremost on the safety and well-being of our colleagues. I would like to thank all our staff for their professionalism, commitment and the care they continue to show for each other.

Shell has an important role to play in the evolving energy system. We provide the oil and gas people need today, including liquefied natural gas (LNG). We are also helping to build the energy system of the future, with low-carbon energy products and solutions.

We are transforming into a more competitive and resilient business so that we are in the best possible position to support the around a billion people we serve, directly or indirectly, every year. We are building trust in Shell as the investment case and partner of choice in a complex and changing world.

At the heart of Shell's transformation is our focus on performance, discipline and simplification. We are embedding this focus across our organisation, from the way we make investment decisions to how we reshape our retail network and maintain our oil and gas platforms, improving reliability and production.

More value with less emissions

I am proud of how far we have come with our strategy to deliver more value with less emissions, and grateful for the commitment and hard work of everyone at Shell through a time of considerable change. We set out to build a strong track record of performance, and we have done just that.

In 2025, we delivered on the financial targets that we set out at our Capital Markets Day 2023 and, as a result, we set more ambitious financial targets at our Capital Markets Day 2025. We reached \$5.1 billion in structural cost reductions* by the end of 2025, compared with 2022, three years ahead of our target, with more to come.

We are on track to achieve our target to grow normalised free cash flow per share* by more than 10% per year [C] through to 2030, underpinned by the growth we expect from our Integrated Gas and LNG, Upstream and Marketing businesses, as well as the steps we are taking to turn around underperforming capital investment.

We saw that growth reflected in our 2025 performance. Our LNG sales increased by 11%, with a record number of LNG cargoes, supporting our aim of a 4-5% increase per year to 2030 [C]. Our Mobility and Lubricants businesses also produced their best-ever results, amid rising demand for premium products.

2025 at a glance

2.1

Fatality and permanent impairment frequency (FPI-F) in Shell-operated ventures (2024: 1.7) [A]

\$18.1 billion

Income for the period (2024: \$16.5)

\$42.9 billion

Cash flow from operating activities (2024: \$54.7)

\$18.9 billion

Capital expenditure (2024: \$19.6)

\$13.9 billion

Share buyback programme (2024: \$13.9)

53 million tonnes

Scope 1 and 2 emissions CO₂e (2024: 58)

62

Tier 1 and Tier 2 process safety incidents (2024: 89) [B]

\$18.5 billion

Adjusted Earnings* (2024: \$23.7)

\$26.1 billion

Free cash flow* (2024: \$39.5)

\$20.9 billion

Cash capital expenditure* (2024: \$21.1)

\$8.5 billion

Dividends paid (2024: \$8.7)

71 gCO₂e/MJ

Net carbon intensity (NCI) (2024: 71)

● Performance against our longer-term targets. See pages 14-15.

■ Key performance indicators. See pages 16-17.

[A] FPI-F for 2024 has been revised from 1.5 to 1.7. See safety performance on page 113.

[B] Tier 1 and Tier 2 process safety incidents for 2024 has been revised from 90 to 89. See safety performance on page 113.

At the same time, we continued to invest in the long-term strength of our Upstream portfolio. We increased our interests across our leading deep-water portfolio in the Gulf of America, Brazil and Nigeria, and invested in oil and gas exploration to expand our core positions and secure potential new opportunities.

In 2025, we delivered shareholder distributions at the top end of our target of 40–50% of cash flow from operations* through the cycle [D]. We ended the year with one of the strongest balance sheets in our industry, putting us in a good position for counter-cyclical opportunities.

We are making solid progress towards our climate-related targets and ambition. By the end of 2025, we had achieved around 70% of our target to halve our Scope 1 and 2 operational emissions by 2030, compared with 2016. At the same time, we reduced the net carbon intensity of the energy products we sell by 9%, compared with 2016, moving towards our target of a 15–20% reduction by 2030. By the end of 2025, we had also reduced emissions from the use of our oil products by 18% compared with 2021, as we progress towards our ambition of a 15–20% reduction by 2030. In a significant milestone for 2025, we achieved our target to eliminate routine flaring from our upstream-operated assets.

While we have delivered in many areas, there is still more to do. Our starting point must be safety. It must remain our number one priority. In 2025, four colleagues tragically lost their lives in our operated businesses. I feel that deeply, not just as a CEO but also as a colleague. We owe it to them – and to everyone who works for us – to learn from these incidents, and prevent such tragedies from ever happening again.

Integrated energy company

As we look to the future, we are making real progress on our strategy to deliver more value with less emissions, putting us in a good position to achieve our vision [E] to be the world's leading integrated energy company.

Firstly, we took important steps to grow our integrated gas and LNG business. Gas, especially in the form of LNG, is a stabilising force in the energy system, providing flexibility, reliability and security of supply. It is also a lower-carbon alternative to coal for industry and power, and to diesel and fuel oil for heavy-duty transport and shipping. That is why we believe that supplying LNG will be the biggest contribution we will make to the energy transition over the next decade.

In June, the first cargoes left our LNG Canada joint venture, crossing the Pacific Ocean to meet fast-growing demand from customers in Asia. In 2025, we also completed the acquisition of Pavilion Energy in Singapore, strengthening our LNG trading portfolio.

Secondly, we continued to focus on keeping liquids production stable, as oil will be essential for the energy system for decades to come. We plan to deliver new projects with more than 1 million barrels of oil equivalent a day by 2030, and we have already added a quarter of that production to our portfolio.

In 2025, we achieved our highest-ever quarterly production in Brazil, and our highest quarterly production since 2005 in the Gulf of America. We reached these record levels through the successful start-up of new projects such as Whale in the Gulf of America, which reached nameplate capacity in less than half the expected time.

We increased our stake in the Ursa platform in the Gulf of America, unlocking more value from another asset that achieved a strong operational performance in 2025. And in May, production started at the Mero-4 floating production, storage and offloading facility, around 180 kilometres off the coast of Rio de Janeiro, further strengthening our cost- and carbon-competitive deep-water portfolio.

We took an important step in the repositioning of our Upstream portfolio with the divestment of The Shell Petroleum Development Company of Nigeria Limited (SPDC) in March 2025. In the UK, we also started a new chapter with our Adura joint venture, one of the largest independent oil and gas producers in the UK North Sea.

Premium products

Thirdly, we continued to transform our Downstream, Renewables and Energy Solutions businesses. In our Marketing business, we achieved strong results as we continued to reshape our portfolio with the closure or sale of around 800 lower-performing branded retail sites.

Our disciplined approach to capital allocation meant some tough choices. In 2025, we completed the divestment of our Energy and Chemicals Park in Singapore, and stopped construction of our Rotterdam biofuels plant in the Netherlands because it would not have been competitive enough to meet our customers' needs for affordable, low-carbon products. In power, we withdrew from projects like the Atlantic Shores Offshore Wind project in the USA to focus on energy storage, flexible generation and trading.

Our focused approach puts us in a better position to serve our customers. The Northern Lights joint venture, for example, has already transported CO₂ from its first industrial customers and injected it beneath the Norwegian Sea. Northern Lights is now moving forward with phase two, which will more than double its storage capacity. In the Netherlands, construction of Holland Hydrogen I, one of Europe's largest renewable hydrogen plants, is progressing well.

We will continue to look for opportunities where we can create value for our shareholders. Today we have around \$20 billion of our capital employed* across lower-carbon platforms, including power (both gas-fired and from renewable energy), low-carbon fuels, hydrogen, and carbon capture and storage [F]. We will develop them as government policies and customer demand help create attractive business models.

We believe governments need to provide the predictability and stability that companies like Shell need for long-term investments. We saw some examples of this in 2025, with the German government's move to implement the European Union's Renewable Energy Directive. This requires increases in the share of renewable energy within the electricity, heating, cooling, transport and industrial sectors.

Unlocking potential

To achieve our vision, we must unlock the full potential of all our businesses, supported by our world-class trading and optimisation capabilities. I saw that potential for myself when I visited with LNG Canada staff in September. It is impressive how different parts of Shell work together – producing the gas, turning it into LNG and shipping the LNG to our customers. I sat with our traders as they worked side by side with production operators to unlock even more value.

I remain extremely grateful to all our staff who are transforming our great organisation into the best version that we can be. Their hard work and determination have made Shell much stronger. I am proud of our commitment to simplify, enable faster decisions and deliver the full value of being an integrated business.

That is why I am confident saying that customers can trust that Shell will deliver for them, that investors can trust that we will give them attractive returns, and that partners can trust that we will be there when they need us. In short, 'you can be sure of Shell'.

Wael Sawan
Chief Executive Officer

[C] On a compound annual growth rate (CAGR) basis.

[D] Measured across business cycles under varying economic and market conditions.

[E] A vision statement defines the desired future state of a company rather than a series of firm, binding commitments.

[F] Gas is a lower-carbon alternative to coal in power generation.

* Non-GAAP measure. See page 430.



This is Shell

Shell is a global group of energy and petrochemical companies, employing around 85,000 people [A] across more than 70 countries. Our activities include oil and gas exploration and production, and the marketing of fuels, lubricants and chemical products. We also offer low-carbon energy products and solutions.

For more than a century, Shell has been at the heart of the global energy system, fuelling people's homes, industries and transport from cars to planes and ships. Shell provides energy, directly or indirectly, to around a billion people every year.

Our purpose is to power progress together by working with each other, our customers and our partners to provide the energy products people need to power their lives and businesses. Our vision [B] is to become the world's leading integrated energy company – delivering impact at scale, connecting energy and people, matching supply to demand.

With global demand for energy increasing, coupled with the challenge of climate change, we will continue to focus on our strategy to deliver more value with less emissions. We are positioning Shell to become a leaner, more competitive organisation to succeed through a multi-decade energy transition.

As the energy system evolves, at different paces in different places, we will continue to earn trust in Shell by providing stability through an uncertain and complex energy transition.

We seek to build strong, trusted relationships with all our stakeholders. Our stakeholders include: our employees, contractors and pensioners; the investor community; customers, comprising commercial and industrial customers, as well as the millions we serve daily at our retail sites; our suppliers and strategic partners; regulators and governments; non-governmental organisations, civil society, academia and think tanks; and the communities where we work.

Partner of choice

We will leverage our global footprint, trust in our brand, trading and technology capabilities, and our assets and infrastructure to be the energy company that customers and countries choose to be their partner of choice.

Our clear financial targets and climate-related targets and ambition, and our principles of performance, discipline and simplification, will help enable us to realise our vision. The quality of our people and our performance culture ensure we have the right skills, mindset and behaviours. The extraordinary community of talent that powers Shell will approach the next decade of the energy transition with determination.

The Shell Performance Framework (SPF) sets out how we operate across the company. It brings together key components – such as context, direction, culture, structure, people, processes and continuous improvement – to help ensure that the organisation is aligned behind a consistent way of working.

Our performance culture

People are key to our success and we expect everyone who works for Shell to behave according to our core values: honesty, integrity and respect for people. We are transforming Shell to be a more competitive business as we focus on performance, discipline and simplification across our organisation.

We are building a culture that we believe will help us succeed as we navigate the energy transition.

We encourage four attitudes and behaviours from our people:

We deliver results: we deeply understand our businesses, simplifying and improving every day. We are disciplined in working towards meeting our promises even when the unexpected happens.

We learn and adapt: we navigate uncertainty and adapt in a rapidly changing world. We value and grow our expertise. We learn from setbacks to accelerate progress.

We are one team: we listen to different views to make better data-based decisions. We work together with our customers, communities and countries to consistently deliver on our promises.

We care: we care about each other, our work, our values, ethics and diversity, equity and inclusion. This builds trust and is key to our performance as we grow to be our best and deliver commercial outcomes.

The Board assesses and monitors our culture and how it is embedded in our attitudes and behaviours, including in our activities and stakeholder relationships. See "Board activities" on page 153 and "Culture" on page 137.

[A] At December 31, 2025, and including portfolio companies.

[B] A vision statement defines the desired future state of a company rather than a series of firm, binding commitments.

Strong foundations

We will work according to our core values of honesty, integrity, and respect for people. We care about each other, our work, and about doing business the right way – with a focus on safety, people and sustainability. We are committed to doing business in an ethical and transparent way.

The nature of our operations exposes us to a wide range of safety risks. As we implement our strategy, we will continue to focus on achieving our Goal Zero ambition: to do no harm to people and to have no leaks across operations. This goal lies at the very heart of our plans and our activities, and we work to ensure our people are prepared to respond if something goes wrong.

The Shell Code of Conduct explains how employees, contractors and anyone else acting on behalf of Shell must behave, and the Shell General Business Principles (SGBP) set out our responsibilities to all our stakeholders.

We believe that no business can succeed without an unwavering commitment to respecting nature and the communities within which it works. For almost three decades, our commitment to contribute to sustainable development has been part of the SGBP. This requires balancing short- and long-term interests, and integrating economic, environmental and social considerations into business decision-making.

We seek to manage our impact on people, while working to protect nature, increase reuse and recycling, support biodiversity and use resources efficiently. We also strive to make a positive impact on people around the world, and this includes providing the energy people need, contributing to local economies and communities, championing inclusion and respecting human rights.

Our promise that you can be sure of Shell is based on continuity in character and values, and commitment to the people we work with, to the customers we serve and to the investors for whom we are working to deliver more value with less emissions.

What sets us apart

Deep-water expertise	We have almost five decades of deep-water expertise and continue to develop innovative designs for oil and gas assets, replicating successful projects to deliver more value with less emissions. Our deep-water business has a track record of sustained cash flow.
Integrated gas and LNG capability	We are the world's leading publicly listed supplier of LNG with a worldwide network of customers, extensive shipping and storage assets, and access to regasification plants. Our Integrated Gas portfolio is the largest among peers, servicing nearly a fifth of global LNG demand. Our diversified and global portfolio of plants and terminals enhances our resilience to market shocks and allows us to capitalise on price volatility.
Brand leader in mobility and lubricants	Shell is the world's number one finished lubricants supplier and a leader in mobility with a first-class customer-centric network. By prioritising value over volume and focusing on premium fuels and lubricants, we deliver stronger returns today and stay relevant as customer needs evolve.
Technology and innovation	Shell has a long history in technology and innovation. We have a global network of research and development centres and work closely with our customers, suppliers and partners. We also collaborate with leading technology companies to deploy digital solutions at scale across our businesses.
Integrated business model – trading and optimisation	Shell produces energy and is also one of the world's largest and most experienced energy traders and suppliers. We can identify and meet a customer's needs quickly. Our value chains are enhanced by our logistics infrastructure, purchases from third parties and a leading global position in energy markets.

Our businesses

Integrated Gas

Reporting segments

Integrated Gas includes natural gas and liquids exploration and extraction. The gas is then processed to produce liquefied natural gas (LNG) or converted into gas-to-liquids (GTL) fuels and other products. The business includes the operation of both upstream and midstream infrastructure necessary to deliver natural gas and its derivatives to market. Integrated Gas also includes the marketing, trading and optimisation of LNG.

See pages 28-34 for a review of our performance.

Upstream

Upstream explores for and extracts crude oil, natural gas and natural gas liquids. The segment also includes marketing and transportation of oil, gas and liquids, supported by the infrastructure required to deliver them to market or to process them within Shell's chemicals manufacturing plants and refineries. Upstream activities span deep-water and conventional oil and gas operations.

See pages 35-43 for a review of our performance.

Downstream, Renewables and Energy Solutions

Marketing includes Mobility, Lubricants, and Sectors and Decarbonisation. Mobility operates our retail network, including electric vehicle charging, convenience retail, and the Wholesale Commercial Fuels business for transport and industry. Lubricants produces, markets and sells products for road transport and machinery in manufacturing, mining, power generation, agriculture and construction. Sectors and Decarbonisation supplies fuels, speciality products and services, including low-carbon energy solutions such as biofuels, to a broad range of commercial customers, including in the aviation, marine and agriculture sectors.

See pages 52-56 for a review of our performance.



Chemicals and Products includes chemicals manufacturing plants with their own marketing network, and refineries which turn crude oil and other feedstocks into a range of oil products which are moved and marketed around the world for domestic, industrial and transport use. The segment also includes the pipeline business, trading and optimisation of crude oil, oil products and petrochemicals.

See pages 57-63 for a review of our performance.

Renewables and Energy Solutions encompasses renewable power generation, marketing, trading, and optimisation of power and pipeline gas. It also includes hydrogen production, commercial carbon capture and storage (CCS) hubs and carbon credits. The business invests in nature-based projects that compensate for carbon emissions and Shell Ventures, which invests in or works with start-ups and other early-stage businesses to help them scale up and grow.

See pages 64-68 for a review of our performance.



Our strategy

Our strategy is to deliver more value with less emissions. We will continue to drive the transformation of Shell into a leaner and more competitive organisation while delivering resilient returns and rewarding our shareholders. As we transform, we will maintain our focus on performance, discipline and simplification. We will:

Grow our integrated gas and LNG business

Grow LNG sales 4–5% (CAGR) per year through to 2030 [A].

With our leadership position in LNG and the growing role of natural gas in the global energy system, we are pursuing LNG sales growth. Gas, including LNG, is a stabilising force in energy systems because it is versatile, flexible and reliable. Gas is versatile because it can be used in power generation, industry, heating and transport. It is also flexible and reliable because it is simple to deploy and can be shipped, as LNG, to where it is needed to meet changing demand. Gas can balance renewable energy to provide stability for national grids.

Our global trading and supply network enhances the value of our gas portfolio, enabling us to capture opportunities from market volatility while providing secure energy to customers across the world.

Keep liquids production stable

Sustain liquids production at 1.4 million barrels per day, while growing total production by 1% through to 2030 [B].

The role of oil and gas will be critical to the energy system for decades to come. We are focused on our leading deep-water and strong

conventional oil and gas businesses. We are committed to delivering value over the long term from our advantaged portfolio of assets and differentiated set of capabilities. These businesses are highly complementary, as conventional oil can offer price resilience while deep-water can provide price upside with its high-margin barrels.

We aim to sustain liquids production through to 2030 and will focus on basins where we have a competitive advantage. We will prioritise cost- and carbon-competitive molecules.

Transform Downstream, Renewables and Energy Solutions

Drive cash flow resilience and higher returns through disciplined capital allocation.

Shell operates a diverse portfolio. This portfolio includes Mobility, Lubricants and our high-graded Products portfolio which covers refined products supported by our global trading and supply capabilities. We are focused on enhancing value from these businesses which deliver resilient cash flow.

We are repositioning Chemicals, power and existing low-carbon options (including CCS, hydrogen and low-carbon fuels) to unlock greater value. We will continue to focus on adjusting investments and business models based on evolving market demand.

Our strategy is to deliver more value with less emissions



Grow our integrated gas and LNG business

- Grow LNG sales 4–5% per year through to 2030 [A].



Keep liquids production stable

- Sustain liquids production at 1.4 million barrels per day, while growing total production by 1% through to 2030 [B].



Transform Downstream, Renewables and Energy Solutions

- Drive cash flow resilience and higher returns through disciplined capital allocation.

[A] On a compound annual growth rate (CAGR) basis.

[B] Upstream and Integrated Gas.

More value

At Capital Markets Day 2025, we set out a financial framework that will support us in delivering more value.

We are driving improvements in free cash flow generation through disciplined capital allocation, the optimisation of our portfolio, cost efficiency and improved operational performance, including measures such as increasing asset availability and utilisation. This will support us in achieving our target to grow normalised free cash flow per share* by more than 10% on average per year [A] to 2030.

We plan cash capital expenditure* within the range of \$20–22 billion per year between 2025 and 2028, with \$21 billion in 2025. In addition, we are targeting 40–50% of our cash flow from operating activities through the cycle for shareholder distributions* [B].

Furthermore, we will continue to reduce structural costs, targeting \$5–7 billion in cumulative savings by the end of 2028 compared with 2022. By the end of 2025, we had already achieved structural cost reductions* of \$5.1 billion since 2022 with more to come. Nearly 60% of the structural cost reductions have come from operational efficiencies, a leaner corporate centre and faster value-based decision-making.

Less emissions

As we work to deliver more value, we must also navigate the multi-decade energy transition. We have a target to become a net-zero emissions energy business by 2050.

To help achieve the 2050 target, we also have a target to halve absolute Scope 1 and 2 emissions under our operational control by 2030, on a net basis, compared with 2016. As of 2025, we have already achieved some 70% of that target. These are the emissions that come directly from our operations and from the energy we buy to run our operations. For example, we are progressing with improving the energy efficiency of our operations and using more renewable electricity to power our activities. We also have a target to maintain methane emissions intensity for our operated oil and gas assets below 0.2% and achieve near-zero methane emissions intensity by 2030 [C].

In addition, we have a target to cut the net carbon intensity (NCI) of the products we sell by 15–20% by 2030 compared with 2016. And, we are on track, delivering 9% by end-2025 compared with 2016.

Achieving our ambition to reduce customer emissions from the use of our oil products [D] by 15–20% by 2030, compared with 2021, means reducing sales of oil products, as we support customers as they move to electric mobility and low-carbon fuels, such as biofuels. By the end of 2025, we had achieved an 18% reduction.

See "Less emissions" on pages 72–102.

[A] On a compound annual growth rate (CAGR) basis.

[B] Subject to Board approval.

[C] Methane intensity is measured and calculated separately for oil and gas assets with marketed gas (gas, LNG and GTL available for sale) and assets without marketed gas (oil and gas assets where gas is reinjected).

[D] Scope 3, Category 11.

* Non-GAAP measure. See page 430.

Executing our strategy

Our ability to adapt to the dynamic energy landscape and evolving market conditions will be essential to our long-term success. We are shaping our portfolio to focus on areas of competitive advantage, supported by disciplined capital allocation, global customer reach and world-class trading and supply capabilities.

In 2025, we executed several deliberate value-driven decisions to strengthen our businesses.

In Upstream, we completed the divestment of The Shell Petroleum Development Company of Nigeria, the conclusion of a major multi-year effort. We also completed the formation of the Adura Energy Limited joint venture, which is one of the largest independent producers in the UK North Sea. And, in Chemicals and Products, we divested our asset in Singapore as we are working to reposition our portfolio to unlock further value. These decisive actions demonstrate our focus on value.



Photos: Our people are essential to our strategy of delivering more value with less emissions. We are transforming Shell into a leaner, more competitive organisation as we focus on performance, discipline and simplification. Whale platform, Gulf of America, 2025.

Capital Markets Day 2025 presented an update to our financial targets.

We are focused on driving performance, enhancing capital efficiency and unlocking value across our portfolio.

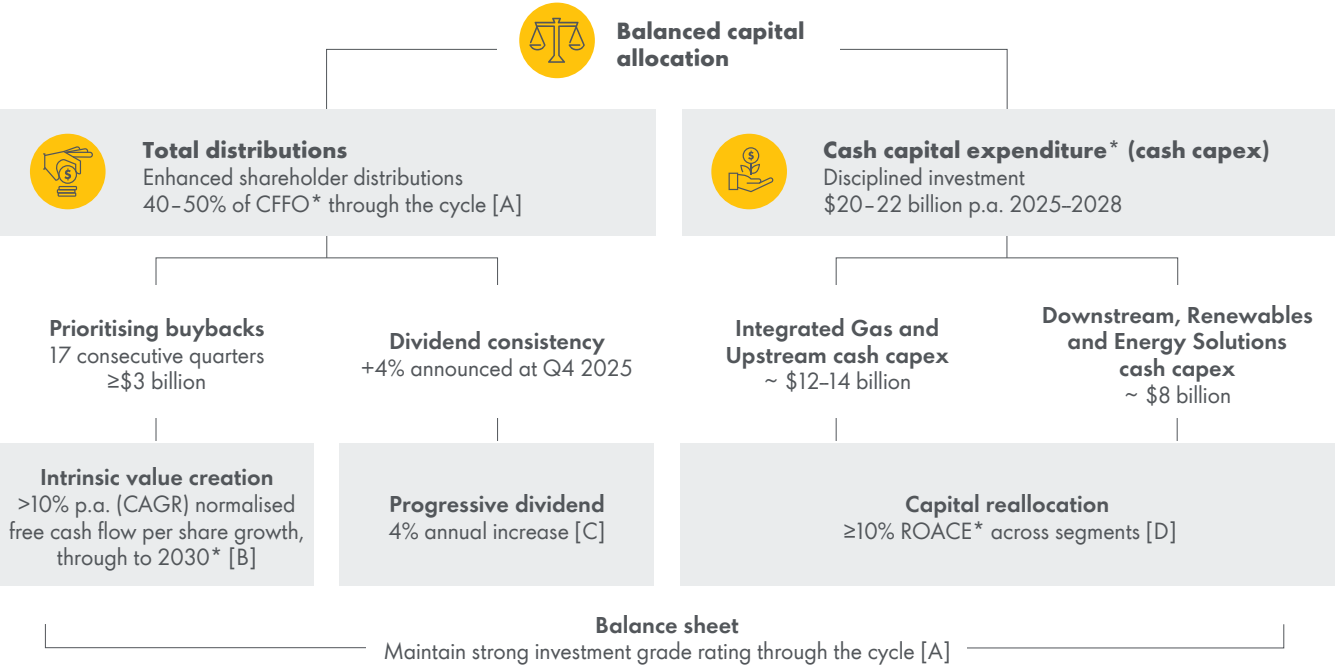
Financial discipline and strategic focus

Our strengthened financial framework positions us to drive long-term value creation, with disciplined capital allocation and a commitment to deliver resilient returns through the cycle [A]. Continued improvements in operational performance, cost discipline and strategic investment in high-return opportunities will underpin this journey.

Updates to our financial targets:

- Enhance shareholder distributions from 30–40% to 40–50% of cash flow from operating activities* through the cycle [A], continuing to prioritise share buybacks while maintaining the 4% a year progressive dividend policy [C].
- Increase the structural cost reduction* target from \$2–3 billion by the end of 2025 to a cumulative \$5–7 billion by the end of 2028, compared with 2022.
- Maintain capital discipline with cash capital expenditure* range lowered to \$20–22 billion a year for 2025–2028 from \$22–25 billion a year for 2024–2025.
- Grow normalised free cash flow per share* on average by more than 10% a year through to 2030 [B].

Shell financial framework: a value-led approach to capital allocation



[A] Measured across business cycles under varying economic and market conditions.

[B] On a compound annual growth rate (CAGR) basis.

[C] Subject to Board approval. When the Board sets the level of shareholder distributions, it looks at a range of factors including the macro environment, underlying business earnings and Group cash flows, the current balance sheet, future investment, acquisition and divestment plans, and existing commitments.

[D] Price-normalised return on average capital employed (ROACE) on an Adjusted Earnings plus non-controlling interest basis.

The statements in this "Our strategy" section are forward-looking statements based on our operating plan, management's current expectations and certain material assumptions and, accordingly, involve risks and uncertainties that could cause actual results, performance or events to differ materially from those expressed or implied herein.

See "About this Report" on pages v-vi and "Risk management and risk factors" on pages 125-135.

* Non-GAAP measure. See page 430.

How we create value

Through our business activities we create value for our shareholders, customers and wider society. This is a non-exhaustive illustration of Shell's key business activities that deliver the energy needed for today.

Our inputs [A]

Financial capital

Equity attributable to Shell plc shareholders (\$ billion) [B]:
174 2024: 178

Total debt (\$ billion) [B]:
76 2024: 77

Net debt* (\$ billion) [B]:
46 2024: 39

Average capital employed* (\$ billion) [B]:
219 2024: 225

Cash capital expenditure* (\$ billion):
21 2024: 21

Operations

Refinery and chemical plant availability: ■
94% 2024: 92%

Oil & gas production available for sale (kboe/d):
2,800 2024: 2,836

LNG liquefaction volumes (million tonnes): ■
28 2024: 29

Our people

Number of employees (thousands) [B]:
85 2024: 96

Number of training days (thousands):
253 2024: 264

Relationships

Ranking in the Global 500 list of most valuable oil and gas companies [C]:
1 2024: 1

Customers, joint arrangements, government relations, suppliers.
Number of operating countries [B]:
>70 2024: >70

Intellectual capital

Research and development expenses (\$ million):
1,170 2024: 1,099

Number of patents [B] [D]:
8,087 2024: 8,677

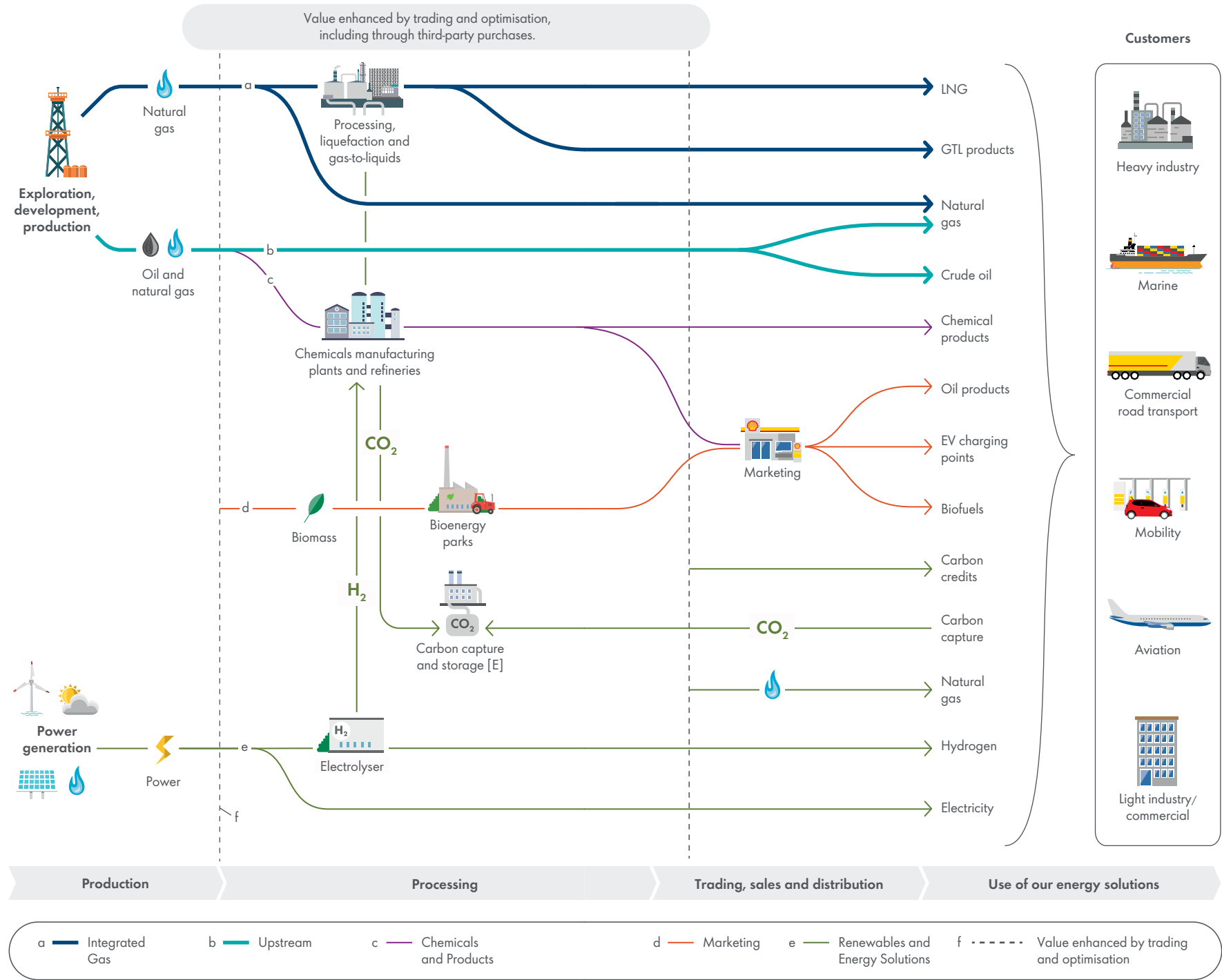
Natural resources

Proved oil and gas reserves (million boe) [B]:
8,123 2024: 9,620

Energy consumed (million MWh):
189 2024: 212

[A] In 2025 unless stated otherwise.
[B] At December 31, 2025.
[C] Source: Brand Finance Global 500.
[D] Includes patents granted and pending patent applications.
* Non-GAAP measure. See page 430.

Business activities



■ Performance indicators (see pages 16-17).
● Progress against our longer-term targets (see page 14-15).

[E] CCS hubs developed to offer CCS-as-a-service to our customers are reported in the Renewables and Energy Solutions segment. Where existing or future CCS projects help to decarbonise our own assets, they will be reported in the segment where the asset sits.

Outcomes and impacts for our stakeholders [A]

	Cash flow from operating activities (\$ billion): ■ 43 2024: 55
	Free cash flow* (\$ billion): 26 2024: 40
	Shareholder distributions* [F] (\$ billion): ● 22 2024: 23
	Adjusted Earnings* (\$ billion): 19 2024: 24
	Absolute emissions (Scope 1 and 2 – million tonnes of CO ₂ equivalent): ● 53 2024: 58 2016: 83
	Net carbon intensity (grams of CO ₂ equivalent per megajoule): ● 71 2024: 71 2016: 78
	Methane emissions intensity: ● 0.04% 2024: 0.04%
	Customer emissions from the use of our oil products [G] (million tonnes of CO ₂ equivalent): 467 2024: 491 2021: 569
	Safety: Fatality and permanent impairment frequency [H] [I]: 2.1 2024: 1.7
	Women employees in senior leadership positions [B]: 35% 2024: 33%
	Total spend on goods and services* (\$ billion) [J]: 40 2024: 41
	Operational spills of more than 100 kilograms (thousand tonnes): 0.16 2024: 1.23

[F] Total shareholder distributions* were \$22 billion, comprising \$8 billion in cash dividends and \$14 billion in share buybacks.
[G] Scope 3, Category 11.
[H] Cases per 100 million working hours.
[I] FPI-F for 2024 has been revised from 1.5 to 1.7. See safety performance on page 113.
[J] 2024 comparative figure has been revised from \$42 billion to \$41 billion. See "Non-GAAP measures reconciliations" on pages 430-435 for further details.
* Non-GAAP measure. See page 430.

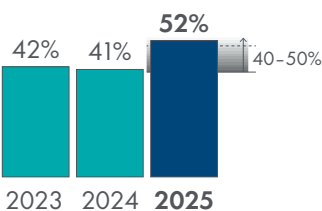
Progress against our longer-term targets

We are successfully implementing our strategy to deliver more value with less emissions and this can be seen in the progress we made in 2025 against the targets below. These targets were set out at our Capital Markets Day in March 2025 and in our Energy Transition Strategy 2024. See "Our strategy" on page 9-11 and "Less emissions" on pages 72-102 for further details.

More value

Targets included at Capital Markets Day 2025 (CMD25)

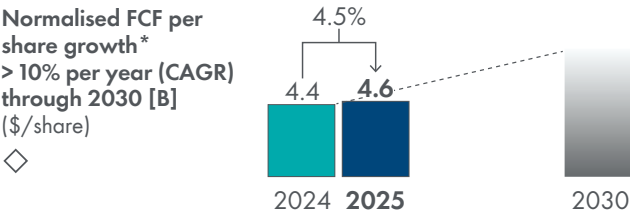
Shareholder distributions 40–50% of CFO* through the cycle [A] (%)



We are committed to delivering shareholder distributions of 40–50% of cash flow from operating activities* (CFO) through the cycle.

In 2025, 52% of CFO was used for shareholder distributions. This was at the top end of our target of 40–50%. Shareholder distributions* of \$22.4 billion comprised \$8.5 billion in dividends and \$13.9 billion in share buybacks.

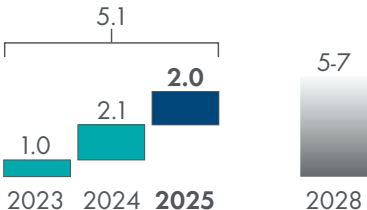
Normalised FCF per share growth* > 10% per year (CAGR) through 2030 [B] (\$/share)



We are committed to increasing cash per share from our core business. Normalised free cash flow (FCF) per share growth demonstrates the growth in underlying business performance and removes inorganic cash flows from acquisitions and divestments, macroeconomic price movements, working capital and derivatives.

In 2025, normalised FCF per share increased by 4.5% compared with 2024.

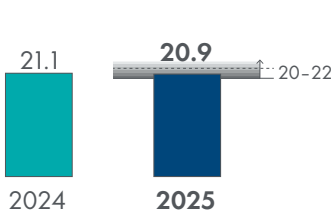
Structural cost reduction* of \$5–7 billion by end of 2028 [C] (\$ billion)



We have achieved structural cost reductions* of \$5.1 billion since 2022, driven by a focus on cost discipline, the simplification of our processes and by streamlining our portfolio.

Of the cost reduction delivered to date, \$2.1 billion relates to portfolio changes and \$3.0 billion relates to operational efficiencies across our businesses, a leaner corporate centre and faster value-base decision-making.

Cash capital expenditure* \$20–22 billion per year 2025–2028 (\$ billion)



In 2025, we maintained capital discipline with cash capital expenditure* of \$20.9 billion, in the middle of the target range of \$20–22 billion a year.

Total cash capital expenditure* in 2025 of \$20.9 billion comprised \$14.0 billion in Integrated Gas and Upstream and \$6.9 in Downstream and Renewables and Energy Solutions.

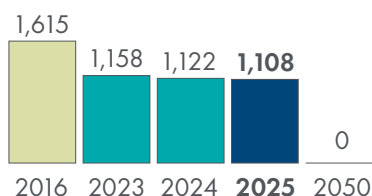
[A] Measured across business cycles under varying economic and market conditions.
[B] On a compound annual growth rate (CAGR) basis.
[C] 2028 target reflects cumulative savings achieved by end of 2028 from 2022 levels.
* Non-GAAP measure. See page 430.

◇ From 2026 the Normalised FCF per share growth target will be a performance condition used to determine Executive Director's remuneration.
See "Directors' Remuneration Report" on pages 176-182.

Less emissions

Targets included in our Energy Transition Strategy 2024

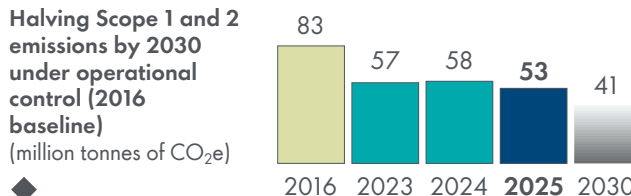
Net-zero emissions by 2050 (Scope 1, 2 and 3)
(million tonnes of CO₂e)



Net absolute emissions included in our NCI decreased slightly in 2025 compared with 2024. Higher emissions from the use of the LNG we sell were offset by lower emissions from the use of our oil products.

We have a target to become a net-zero emissions energy business by 2050.

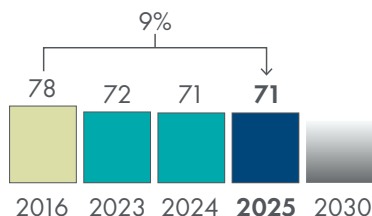
Halving Scope 1 and 2 emissions by 2030 under operational control (2016 baseline)
(million tonnes of CO₂e)



We have reduced our combined Scope 1 and 2 emissions by 36% since 2016. Our emissions were lower compared with 2024, mainly due to portfolio changes and abatement projects.

We have a target to halve the emissions from our operations (Scope 1) and the energy we buy to run them (Scope 2) by 2030 compared with a 2016 baseline, on a net basis.

Reduce the NCI of the products we sell by 15–20% by 2030 [D]
(gCO₂e/MJ)



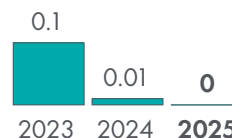
With a reduction of 9.0% compared with the 2016 baseline, we have met our interim target to reduce the net carbon intensity (NCI) of the products we sell by 9–13% in 2025.

We use the NCI metric to track progress in reducing the overall carbon intensity of the energy products we sell, compared with a 2016 baseline. NCI is the average intensity, weighted by sales volume, of the energy products we sell.

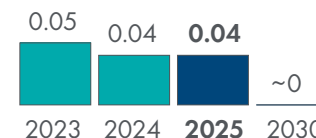
Eliminate routine flaring from upstream operations by 2025 [E]. Maintain methane emissions intensity below 0.2% and achieve near-zero methane emissions intensity by 2030



Routine flaring
(million tonnes) [F]



Methane emissions intensity
(%) [G]



We met our target of ending routine flaring from upstream operations in January 2025. This was independent of the March 13, 2025 completion of the sale of The Shell Petroleum Development Company of Nigeria Limited (SPDC). We continue to deliver methane emissions intensity well below our 0.2% target.

In addition to these targets we have an ambition to reduce the customer emissions from the use of our oil products by 15–20% by 2030, compared with 2021 (Scope 3, Category 11). See "Less emissions" on page 96.

[D] Grams of carbon dioxide equivalent per megajoule.

[E] This target was subject to the completion of the sale of SPDC.

[F] Routine flaring for 2024 has been revised from 0.1 million tonnes to 0.01 million tonnes. See "Routine flaring" on page 89 for details.

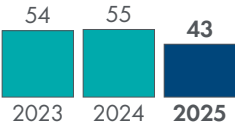
[G] Methane emissions intensity of Shell-operated oil and gas assets with marketed gas.

◆ This target is used to determine Executive Directors' remuneration. See "Directors' Remuneration Report" on pages 176-182.

Performance in the year

Financial delivery

Cash flow from operating activities (\$ billion)



Total cash receipts and payments associated with oil, gas, chemicals and other product sales. This reflects our ability to generate cash to service and reduce debt, invest and make shareholder distributions.

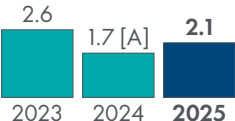
2025 performance

The decrease was primarily driven by lower earnings, despite stronger operational performance, due to a lower price environment and working capital outflows.

See "Liquidity and capital resources" on pages 21-24.

Safety

Personal safety (FPI-F cases per 100 million working hours)

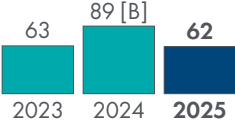


Fatality and permanent impairment (FPI) is defined as a serious work-related injury or illness that resulted in a fatality or permanent impairment. For FPI frequency (FPI-F), the number of FPI employee and contractor incidents is divided by 100 million working hours.

2025 performance

There can be no compromise on safety. Last year's four fatalities and four serious injuries remind us that everyone must go home safely. With outcomes declining versus the prior year, we must further strengthen our safety focus.

Process safety (number of Tier 1 and Tier 2 events)



Operational process safety events are defined as the unplanned or uncontrolled release of any material from a process with the greatest actual consequence resulting in harm to employees, contract staff, a neighbouring community, or damage to equipment, or exceeding a threshold quantity.

2025 performance

Notable improvement in process safety tiered events was mainly driven by our Downstream, Renewables and Energy Solutions businesses. We are actively addressing remaining challenges by enhancing operational discipline, reinforcing focus on core fundamentals, and leveraging new technologies.

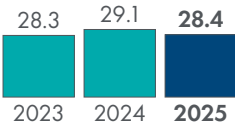
For details on our safety performance see "Safety" on pages 111-113.

Performance indicators

These indicators enable management to evaluate Shell's performance against our annual Operating Plan. They are also used as part of determining Executive Directors' remuneration. See "Directors' Remuneration Report" on pages 176-182.

Shell's journey in the energy transition

LNG volumes (million tonnes)



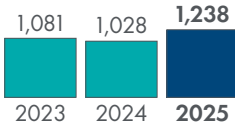
Shell's share of sales of equity LNG volumes from liquefaction plants owned by Shell subsidiaries, Shell joint ventures and associates, and Shell's share of LNG produced from liquefaction plants which operate under tolling arrangements with Shell.

2025 performance

LNG liquefaction volumes decreased mainly due to ownership restructuring in Trinidad and Tobago and higher maintenance across the portfolio.

See "Integrated Gas" on pages 28-34.

Reducing operational emissions (Scope 1 and 2; thousand tonnes CO₂e)



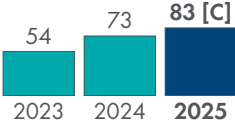
Operational emission reductions achieved from greenhouse gas (GHG) abatement projects (e.g. reduced flaring, increased energy efficiency, and use of renewable electricity), site closures and decommissioning or transformations, resulting in sustained GHG reductions.

2025 performance

This year's stronger performance was mainly supported by multiple transformation projects at the Energy and Chemicals Park Rheinland in Germany, compressor electrification in Canada, and catalyst improvements in Qatar (IG).

See "Less emissions" on pages 72-102.

Electric vehicle (EV) charge points (thousand)



Number of public electric vehicle charge points owned, controlled or Shell-branded.

2025 performance

The increase in electric vehicle charge points in 2025 was mainly driven by growth in China and Ubitricity's portfolio in the UK.

See "Marketing" on pages 52-56.

[A] FPI-F for 2024 has been revised from 1.5 to 1.7. See safety performance on page 113.

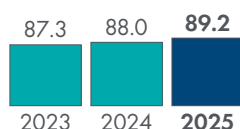
[B] Tier 1 and Tier 2 process safety incidents for 2024 has been revised from 90 to 89.

See safety performance on page 113.

[C] Adjusted to exclude around 4,000 electric vehicle charge points divested, effective January 2, 2026.

Operational excellence

Upstream controllable availability (%)

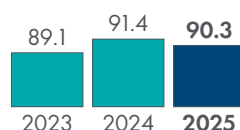


This reflects our ability to optimally run our Upstream assets and includes all Shell-operated assets and selected assets not operated by Shell but for which Shell has strategic influence. It excludes the impact of extreme unexpected events that are outside our control, such as government restrictions and hurricanes. Reliability issues, turnarounds and maintenance at own-operated or third-party facilities impact controllable availability.

2025 performance

Upstream controllable availability increased compared to last year, particularly in Kazakhstan, Brunei, Nigeria and Oman.

Midstream availability (%)

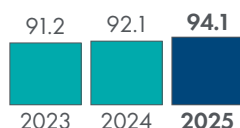


The extent to which LNG assets are ready to process product as a comparison with capacity, considering the impact of planned and unplanned maintenance.

2025 performance

Overall performance declined compared to last year due to higher planned maintenance activities across the portfolio.

Refinery and chemical plant availability (%)



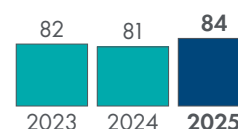
Weighted average of plants' actual uptime, as a percentage of their maximum possible uptime, is a measure of the operational excellence of our refinery and chemical plant facilities. Refining and Chemicals are assigned equal weights.

2025 performance

This year's improvements were driven primarily by strong performance at Deer Park Chemicals and improved performance at Shell Polymers Monaca, supported by enhanced results at the Rheinland and Scotford refineries.

See "Chemicals and Products" on pages 57-63.

Project delivery on schedule (%)

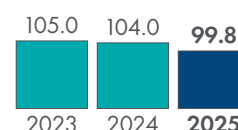


Our capability to complete major projects on time, measured as the percentage of projects delivered on schedule.

2025 performance

The score improved, with highlights for the year including the successful start-up of 21 projects, notably Whale in the Gulf of America, Penguins in the UK, Mero-4 in Brazil and the first export cargo from LNG Canada.

Project delivery on budget (%)

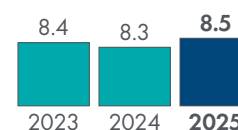


Aggregate cost against the aggregate baseline for those projects where a figure greater than 100% means over budget.

2025 performance

The score improved, reflecting steady progress and strong overall performance across ongoing projects.

Customer satisfaction (index)

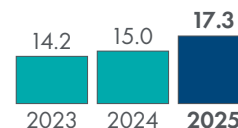


This quantitative measurement of customer experience performance is calculated as an average of customer satisfaction scores from the global business-to-business transactional survey programme.

2025 performance

This year's improvements reflected focus on performance, continuous improvement of e-commerce platforms, and the resilience of our teams.

Brand Share Preference (%)



The percentage of customers answering "Shell" when asked: "Assuming that all the fuel station companies that you would consider are conveniently located, which one company do you prefer most?" The responses are taken from survey respondents in more than 60 countries covering both fuel and non-fuel retail consumers.

2025 performance

Our Brand Share Preference continued to rise, performing well in all regions. The improvement was mainly driven by Asia.



More value

We will drive improved performance, embed cost and capital discipline, and make fundamental decisions across our portfolio to deliver more value for our shareholders through a progressive dividend policy and by prioritising share buybacks.

In 2025, we delivered solid financial results with Adjusted Earnings* of \$18.5 billion despite a lower price environment. Our performance was driven by strong operational performance, LNG sales growth and portfolio optimisation. Cash flow from operations remained robust, enabling consistent shareholder distributions.

We maintained disciplined capital allocation and achieved structural cost reductions* with cumulative savings of \$5.1 billion since 2022.

* Non-GAAP measure. See page 430.

19	Group results
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Group results

Key metrics

	\$ million, except where indicated		
	2025	2024	2023
Income attributable to Shell plc shareholders	17,837	16,094	19,359
Income for the period	18,119	16,521	19,636
Adjusted Earnings* [A] [B] [C]	18,528	23,716	28,250
Adjusted EBITDA* [B]	56,135	65,803	68,538
Cash flow from operating activities	42,863	54,687	54,191
Cash flow from investing activities	(16,811)	(15,155)	(17,734)
Free cash flow*	26,052	39,533	36,457
Cash capital expenditure*	20,915	21,085	24,392
Operating expenses* [D]	35,675	36,917	39,960
Underlying operating expenses* [D]	35,032	35,707	39,201
ROACE on an Adjusted Earnings plus non-controlling interest basis*	9.4%	11.3%	12.8%
Total debt at December 31 [E]	75,643	77,078	81,541
Net debt* at December 31 [E]	45,687	38,809	43,542
Gearing* at December 31	20.7%	17.7%	18.8%
Oil and gas production available for sale (thousand boe/d)	2,800	2,836	2,791
Basic earnings per share (\$)	3.03	2.55	2.88
Adjusted Earnings per share* (\$)	3.15	3.76	4.20
Dividend per share (\$)	1.446	1.390	1.294

[A] See Note 7 to the "Consolidated Financial Statements" on pages 259-267.

[B] Adjusted Earnings and Adjusted EBITDA are presented on a current cost of supplies basis and exclude identified items; see Note 7 to the "Consolidated Financial Statements" on pages 259-267 and "Non-GAAP measures" on pages 430-435.

[C] Adjusted Earnings exclude the non-controlling interest component.

[D] The most comparable GAAP financial measure is Production and manufacturing expenses (2025: \$21,898 million; 2024: \$23,379 million).

[E] See Note 21 to the "Consolidated Financial Statements" on pages 278-279.

* Non-GAAP measure. See page 430.



"In 2025 our strong operational performance drove solid financial results across Shell, with robust cash flows despite the lower price environment."

Sinead Gorman
Chief Financial Officer

Income/(loss) for the period [A]

		\$ million
Integrated Gas	2023	7,057
	2024	9,590
	2025	8,820
Upstream	2023	8,540
	2024	7,772
	2025	9,443
Marketing	2023	2,690
	2024	1,709
	2025	2,057
Chemicals and Products	2023	1,204
	2024	1,671
	2025	262
Renewables and Energy Solutions	2023	3,089
	2024	(1,229)
	2025	(489)
Corporate	2023	(2,944)
	2024	(2,992)
	2025	(1,974)

Segment Adjusted Earnings* [A] [B]

		\$ million
Integrated Gas	2023	13,919
	2024	11,390
	2025	8,024
Upstream	2023	9,806
	2024	8,395
	2025	7,442
Marketing	2023	3,312
	2024	3,885
	2025	3,994
Chemicals and Products	2023	3,616
	2024	2,934
	2025	1,051
Renewables and Energy Solutions	2023	756
	2024	(497)
	2025	172
Corporate	2023	(2,875)
	2024	(1,968)
	2025	(1,870)

2025 earnings

Income attributable to Shell plc shareholders in 2025 was \$17,837 million, compared with \$16,094 million in 2024. With non-controlling interest included, income for the period in 2025 was \$18,119 million, compared with \$16,521 million in 2024. Income for the period was driven by the same factors as Adjusted Earnings and includes identified items and current cost of supplies adjustment of \$641 million.

Adjusted Earnings* in 2025 were \$18,528 million, compared with \$23,716 million in 2024. The decrease was mainly driven by lower realised liquids and LNG prices, lower trading and optimisation and lower Chemicals margins, partly offset by higher volumes, lower operating expenses, favourable tax movements and higher Marketing margins.

Identified items in 2025 amounted to a net loss of \$53 million and included impairment charges; gains on disposal of assets, mainly related to the incorporation of the Adura Energy Limited joint venture in the UK; and favourable movements due to the fair value accounting of commodity derivatives. This compares with identified items in 2024 which amounted to a net loss of \$7,364 million.

For details of earnings by segment see "Integrated Gas" on page 28, "Upstream" on page 35, "Marketing" on page 52, "Chemicals and Products" on page 57, "Renewables and Energy Solutions" on page 64 and "Corporate" on page 69.

Prior year earnings

Income attributable to Shell plc shareholders in 2024 was \$16,094 million, compared with \$19,359 million in 2023. With non-controlling interest included, income for the period in 2024 was \$16,521 million, compared with \$19,636 million in 2023. Income for the period was driven by the same factors as Adjusted Earnings and includes identified items and current cost of supplies adjustment of \$272 million.

Adjusted Earnings* in 2024 were \$23,716 million, compared with \$28,250 million in 2023. The decrease was mainly driven by lower LNG trading and optimisation margins, lower realised prices, lower refining margins as well as lower trading and optimisation margins of power and pipeline gas in Renewables and Energy Solutions, partly offset by lower operating expenses and higher realised Chemicals margins.

Identified items in 2024 amounted to a net loss of \$7,364 million and included net impairment charges and reversals, reclassifications from equity to profit and loss of cumulative currency translation differences related to funding structures, unfavourable movements relating to the fair value accounting of commodity derivatives, and charges related to redundancy and restructuring. This compares with identified items in 2023 which amounted to a net loss of \$8,242 million.

Adjusted EBITDA

Adjusted EBITDA, for 2025 and 2024, was driven by the same factors as Adjusted Earnings and excludes taxation, exploration well write-offs and depreciation, depletion and amortisation expenses for the relevant years.

Cash flow from operating activities

See "Liquidity and capital resources" on page 21.

Cash capital expenditure

See "Liquidity and capital resources" on page 21 and "Less emissions" on pages 81-82.

* Non-GAAP measure. See page 430.

Operating expenses and Underlying operating expenses

Operating expenses* were \$35,675 million in 2025, compared with \$36,917 million in 2024. Underlying operating expenses* were \$35,032 million, compared with \$35,707 million in 2024. These decreases were mainly driven by structural cost reductions delivered through portfolio changes, operational efficiencies, a leaner corporate centre and faster value-based decision-making.

Return on average capital employed (ROACE) on an Adjusted Earnings plus non-controlling interest basis

Our ROACE on an Adjusted Earnings plus non-controlling interest basis* decreased to 9.4%, compared with 11.3% in 2024, mainly driven by lower earnings.

Significant accounting estimates and judgements

See Note 2 to the "Consolidated Financial Statements" on pages 234-244.

Legal proceedings

See Note 32 to the "Consolidated Financial Statements" on pages 302-304.

Production available for sale

Oil and gas production available for sale in 2025 was 2,800 thousand boe/d, compared with 2,836 thousand boe/d in 2024. This decrease was mainly driven by divestments and field decline, partly offset by new production.

Oil and gas production available for sale [A][B]

	Thousand boe/d		
	2025	2024	2023
Crude oil and natural gas liquids	1,494	1,452	1,454
Synthetic crude oil [C]	41	51	52
Natural gas [D]	1,265	1,333	1,285
Total	2,800	2,836	2,791
Of which:			
Integrated Gas	931	954	939
Upstream	1,828	1,831	1,800
Oil sands (part of Chemicals and Products) [C]	41	51	52

[A] See "Oil and gas information" on pages 44-51.

[B] Reflects 100% of production of subsidiaries except in respect of production-sharing contracts (PSC), where the figures shown represent the entitlement of the subsidiaries concerned under those contracts.

[C] In November 2025, we completed the agreement in Canada to swap our remaining 10% mining interest and associated synthetic crude oil reserves in exchange for an additional 10% interest in the Scotford upgrader and Quest Carbon Capture (CCS) facility.

[D] Natural gas volumes are converted into oil equivalent using a factor of 5,800 scf per barrel.

Proved reserves

The proved oil and gas reserves of Shell subsidiaries and the Shell share of the proved oil and gas reserves of joint ventures and associates are summarised in "Oil and gas information" on pages 44-51 and set out in more detail in "Supplementary information – oil and gas (unaudited)" on pages 307-325.

Before taking production into account, our proved reserves decreased by 427 million boe in 2025. Acquisitions and divestments accounted for a net decrease of 1,203 million boe, largely related to the swap transaction involving our synthetic crude oil reserves in Canada (see "Chemicals and Products" on page 57) and the divestment of The Shell Petroleum Development Company of Nigeria Limited (SPDC). Total oil and gas production was 1,070 million boe. Accordingly, after taking production into account, our proved reserves decreased by 1,497 million boe in 2025, to 8,123 million boe at December 31, 2025.

Liquidity and capital resources

Liquidity and capital resources

Shell generated free cash flow* of \$26.1 billion in 2025, aided by disciplined capital management, portfolio simplification and operational performance improvements. Net debt* increased to \$45.7 billion at December 31, 2025 (December 31, 2024: \$38.8 billion). Net debt excluding leases* increased to 16.8 billion (December 31, 2024: 10.1 billion). Total debt decreased to \$75.6 billion at December 31, 2025 (December 31, 2024: \$77.1 billion). Gearing* increased to 20.7% at December 31, 2025, compared with 17.7% at December 31, 2024.

Cash and cash equivalents were \$30.2 billion at December 31, 2025 (December 31, 2024: \$39.1 billion).

See Note 21 to the "Consolidated Financial Statements" on pages 278-279.

Liquidity

Shell satisfies its funding, liquidity and working capital requirements by using cash generated from our operations, taking on debt and through divestments. In 2025, access to the international debt capital markets remained strong, with Shell's debt principally financed from these markets through central debt programmes consisting of:

- two \$10 billion commercial paper (CP) programmes, with maturities between 183 days and 364 days depending on the form of the notes issued;
- an unlimited Euro medium-term note (EMTN) programme (also referred to as the Multi-Currency Debt Securities Programme), which lapsed in November 2024, and was renewed in May 2025; and
- an unlimited US universal shelf (US shelf) registration.

The debt issued under the CP, EMTN and US shelf has historically been issued by Shell International Finance B.V., the primary issuance company for Shell, with its debt being guaranteed by Shell plc. In 2023, Shell incorporated a new US subsidiary, Shell Finance US Inc., and in 2024 and 2025 a portion of the debt issued by Shell International Finance B.V. and BG Energy Capital plc (for 2025) was moved into this entity through exchange offers. Additionally, Shell Finance US Inc. issued new debt in November 2025, which is guaranteed by Shell plc. We expect any new debt issued under the CP programmes, EMTN or US shelf to be guaranteed by Shell plc.

We also maintain an \$8 billion committed credit facility with initial maturity in 2030, however extension options may take final maturity to 2032. This remained fully undrawn at December 31, 2025. This facility replaces the previous \$8 billion facility due to mature in December 2026. This core facility and cash on balance sheet provide backup coverage for our CP programmes. Other than certain borrowings by subsidiaries in their local jurisdictions, we do not have any other committed credit facilities.

Our total debt decreased by \$1.4 billion to \$75.6 billion at December 31, 2025. The total debt excluding lease liabilities matures as follows: 10% in 2026; 6% in 2027; 13% in 2028 and 71% in 2029 and beyond. Debt maturing in 2026 is expected to be repaid from a combination of cash balances, cash generated from operations, divestments and the issuance of new debt. In 2025, we did not issue any debt under the EMTN programme or CP programmes, while issuing \$2.35 billion under the US shelf. The Group had no CP outstanding at December 31, 2025.

While our subsidiaries are subject to restrictions, such as foreign withholding taxes on the transfer of funds in the form of cash dividends, loans or advances, such restrictions are not expected to have a material impact on our ability to meet our cash obligations.

Management believes it has access to sufficient debt funding sources (capital markets) and to undrawn committed borrowing facilities to meet foreseeable requirements.

Market risk, credit risk and pension commitments

Financial risks

We use various financial instruments for managing exposure to foreign exchange and interest rate movements. Our treasury operations are highly centralised and seek to manage credit exposures associated with our substantial cash, foreign exchange and interest rate positions.

Our portfolio of cash investments is diversified to avoid concentrating risk in any one instrument, country or counterparty. Other than in exceptional cases, the use of external derivative instruments is confined to our specialist trading and central treasury organisations that have the appropriate skills, experience, supervision, control and reporting systems.

We operate with procedures and policies designed to help ensure that trading risks are managed within a prescribed control framework. The framework sets out authorised limits and requirements that trading should only be performed by employees with the appropriate skills and experience. Senior management regularly reviews these authorised trading limits. In addition, a department that is independent from our traders monitors our market risk exposures daily, using techniques such as value-at-risk alongside other risk metrics.

We have counterparty credit risk policies in place which seek to help ensure that products are sold to customers with appropriate creditworthiness. These policies include detailed credit analysis and monitoring of customers against counterparty credit limits. Where appropriate, netting arrangements, credit insurance, prepayments and collateral are used to manage credit risk.

A pensions forum chaired by the Chief Financial Officer oversees Shell's input to pension strategy, policy and operation. A risk committee supports the forum in reviewing the results of assurance processes with respect to pension risk. Local trustees manage the funded defined benefit pension plans and set the strategic asset allocation for the plans, including the extent to which currency, interest rate, inflation and longevity risks are hedged. Contributions paid are based on independent actuarial valuations that align with applicable local regulations. Pension fund liquidity is managed by holding appropriate liquid assets and maintaining credit facilities. We also consider opportunities to insure pension liabilities with third parties to reduce this risk.

On July 1, 2023, new pension legislation came into effect in the Netherlands, with implementation required prior to January 1, 2028. In July 2025, the Trustee Board of Shell's defined benefit pension fund in the Netherlands formally accepted the transition plan, related to the changes in pension legislation, to transition from a defined benefit pension fund to a defined contribution plan with effect from January 1, 2027, subject to the local funding level of the plan remaining above an agreed level (125%) during the predetermined transition period.

Our total employer contributions were \$0.6 billion in 2025 and are estimated to be \$1.1 billion in 2026, including a minimum final payment of \$0.3 billion in the Dutch pensions to transform from the defined benefit plan into a defined contribution.

See "Risk factors" on page 130, and Note 24 and Note 26 to the "Consolidated Financial Statements" on pages 284-290 and 292-298.

* Non-GAAP measure. See page 430.

Capitalisation table

	\$ million	
	December 31, 2025	December 31, 2024
Equity attributable to Shell plc shareholders	174,392	178,307
Current debt	9,128	11,630
Non-current debt	66,515	65,448
Total debt [A]	75,643	77,078
Total capitalisation	250,035	255,385

[A] Of total debt of \$75.6 billion (2024: \$77.1 billion), \$46.3 billion (2024: \$48.1 billion) was unsecured and \$29.3 billion (2024: \$29.0 billion) was secured; \$45.0 billion is fully and unconditionally guaranteed by Shell plc (December 31, 2024: \$46.0 billion), with the following amounts issued by Shell Group subsidiaries: \$22.6 billion by Shell International Finance B.V., a wholly owned finance subsidiary of Shell plc (December 31, 2024: \$31.8 billion); \$20.1 billion by Shell Finance US Inc., a wholly owned finance subsidiary of Shell plc (December 31, 2024: \$11.4 billion); and \$2.3 billion by BG Energy Capital plc (December 31, 2024: \$2.8 billion).

See Note 21 to the "Consolidated Financial Statements" on page 278 for further disclosure on total debt and net debt.

Guarantees and other off-balance sheet arrangements

There were no guarantees or other off-balance sheet arrangements at December 31, 2025, or December 31, 2024 that were reasonably likely to have a material impact on Shell.

See Note 26 and Note 32 to the "Consolidated Financial Statements" on pages 292 and 302 for further details on guarantees or other off-balance sheet arrangements where the potential obligations related to issuance are assessed to be remote.

Consolidated Statement of Cash Flows

Cash flow from operating activities (CFFO) in 2025 was \$42.9 billion, compared with \$54.7 billion in 2024. CFFO in 2025 was primarily driven by Adjusted EBITDA* of \$56.1 billion (compared with \$65.8 billion in 2024) and inflows from dividends (net of profits) received from joint ventures and associates of \$2.6 billion (compared with outflows of \$0.3 billion in 2024), partly offset by tax payments of \$11.6 billion (compared with payments of \$12.0 billion in 2024) and working capital outflows of \$1.8 billion (compared with inflows of \$2.1 billion in 2024).

Cash flow from investing activities in 2025 was an outflow of \$16.8 billion, compared with an outflow of \$15.2 billion in 2024. Cash flow from investing activities in 2025 included cash capital expenditure* of \$20.9 billion (compared with cash capital expenditure* of \$21.1 billion in 2024), partly offset by divestment proceeds* of \$2.4 billion (compared with divestment proceeds* of \$2.8 billion in 2024) and interest received of \$2.0 billion (compared with interest received of \$2.4 billion in 2024).

Cash flow from financing activities in 2025 was an outflow of \$35.8 billion, compared with outflows of \$38.4 billion in 2024. This included the repurchases of shares of \$13.9 billion (2024: \$13.9 billion), net repayments of debt of \$9.1 billion (2024: \$9.6 billion net repayment), dividends paid to Shell plc shareholders of \$8.5 billion (2024: \$8.7 billion), interest paid of \$4.1 billion (2024: \$4.6 billion) and favourable debt-related derivative financial instrument movements of \$1.3 billion (2024: \$0.6 billion unfavourable movement).

Prior year Consolidated Statement of Cash Flows

Our Consolidated Statement of Cash Flows for the financial year ended December 31, 2024, compared with the financial year ended December 31, 2023, can be found in the Annual Report and Accounts (page 25) and Form 20-F (page 42) for the year ended December 31, 2024, as filed with the Registrar of Companies for England and Wales and the US Securities and Exchange Commission, respectively.

See "Consolidated Statement of Cash Flows" on page 233.

Cash flow from operating activities

The most significant factors affecting Shell's CFFO are earnings, which are mainly impacted by: realised prices for crude oil, natural gas and LNG; production levels of crude oil, natural gas and LNG; chemicals, refining and marketing margins; timing of dividend payments from joint ventures and associates and movements in working capital and derivative financial instruments.

The impact on earnings from changes in market prices depends on: the extent to which contractual arrangements are tied to market prices; the dynamics of production-sharing contracts; the existence of agreements with governments or state-owned oil and gas companies that have limited sensitivity to crude oil and natural gas prices; tax impacts; and the extent to which changes in commodity prices flow through into operating expenses. Changes in benchmark prices of crude oil and natural gas in any particular period provide only a broad indicator of changes in our Integrated Gas and Upstream earnings in that period. Changes in any factors, from within the industry or the broader economic environment, can and have influenced refining and marketing margins. The precise impact of any changes depends on how the oil markets respond to them. The market response is affected by factors such as: whether the change affects all crude oil types or only a specific grade; regional and global crude oil and refined products inventories; and the collective speed of response of refiners and product marketers in adjusting their operations. As a result, margins fluctuate from region to region and from period to period.

Divestment and cash capital expenditure

The levels of divestment proceeds and cash capital expenditure in 2025 and 2024 reflect our discipline and focus as we continue to implement our strategy. Proceeds from sale of property, plant and equipment and businesses were \$1.1 billion for 2025, compared with \$1.6 billion in 2024. Divestment proceeds* for 2025 were \$2.4 billion, compared with \$2.8 billion in 2024. Cash capital expenditure split by segment is presented in the table below:

Cash capital expenditure* [A]

	\$ million		
	2025	2024	2023
Integrated Gas	4,689	4,767	4,196
Upstream	9,316	7,890	8,343
Marketing [B]	1,862	2,445	5,790
Chemicals and Products	3,063	3,290	3,014
Renewables and Energy Solutions	1,866	2,549	2,681
Corporate	119	144	368
Total cash capital expenditure*	20,915	21,085	24,392

[A] See Note 7 to the "Consolidated Financial Statements" on pages 259-267.

[B] Includes acquisition of Nature Energy in 2023.

* Non-GAAP measure. See page 430.

Capital employed

Capital employed* was \$220.7 billion in 2025, compared with \$218.1 billion in 2024, of which \$20.3 billion related to lower-carbon platforms, including power (both gas-fired and from renewable energy), low-carbon fuels, hydrogen, and carbon capture and storage [A].

[A] Gas is a lower-carbon alternative to coal in power generation.

Contractual obligations

The table below summarises Shell's principal contractual obligations at December 31, 2025, by expected settlement period. The amounts presented have not been offset by any committed third-party revenue in relation to these obligations.

Contractual obligations

	\$ billion				
	Less than 1 year	Between 1 and 3 years	Between 3 and 5 years	5 years and later	Total
Debt [A]	4.5	9.0	6.7	26.8	47.0
Leases	6.3	9.6	6.3	20.0	42.2
Purchase obligations [B]	23.8	25.0	17.6	69.8	136.2
Other long-term contractual liabilities [C]	—	1.1	0.2	0.5	1.7
Total	34.6	44.6	30.8	117.2	227.2

[A] See Note 21 to the "Consolidated Financial Statements" on pages 278-279. Debt contractual obligations exclude interest, which is estimated to be \$1.4 billion payable in less than one year, \$2.7 billion between one and three years, \$2.3 billion between three and five years, and \$11.6 billion in five years and later. For this purpose, we assume that interest rates with respect to variable interest rate debt remain constant at the rates in effect at December 31, 2025, and that there is no change in the aggregate principal amount of debt other than repayment at scheduled maturity as reflected in the table. Lease contractual obligations include interest.

[B] Purchase obligations disclosed in the above table exclude commodity purchase obligations that are not fixed or determinable and are principally intended to be resold in a short period of time through sale agreements with third parties. Examples include long-term non-cancellable LNG and natural gas purchase commitments and commitments to purchase refined products or crude oil at market prices. Inclusion of such commitments would not be meaningful in measuring liquidity and cash flow, as the cash outflows generated by these purchases will generally be offset in the same periods by cash received from the related sales transactions.

[C] Includes obligations included in "Trade and other payables" and provisions related to onerous contracts included in "Decommissioning and other provisions" in "Non-current liabilities" in the "Consolidated Balance Sheet" that are contractually fixed as to timing and amount. In addition to these amounts, Shell has certain obligations that are not contractually fixed as to timing and amount, including contributions to defined benefit pension plans (see Note 24 to the "Consolidated Financial Statements" on pages 284-290) and obligations associated with decommissioning and restoration (see Note 25 to the "Consolidated Financial Statements" on page 291).

Shareholder distributions

We returned \$8.5 billion to our shareholders through dividends and \$13.9 billion through share buybacks in 2025. Total shareholder distributions represented 52% of CFFO*.

The fourth quarter 2025 dividend of \$0.372 per ordinary share will be paid on March 30, 2026, to shareholders on the register at February 20, 2026, and represents an increase of 4% compared with the third quarter 2025 dividend.

See Note 30 to the "Consolidated Financial Statements" on page 302.

Purchases of securities

The intent to purchase shares was announced alongside the quarterly results during 2025, and covered the period up until the next quarterly announcement. In 2025, share buybacks of \$3.5 billion were announced on January 30, \$3.5 billion on May 2, \$3.5 billion on July 31 and \$3.5 billion on October 30 (finalised in the first quarter of 2026). In addition, on February 5, 2026, a further buyback of \$3.5 billion was announced along with the fourth quarter 2025 results; it is intended that this will be completed by the announcement date of the first quarter 2026 results.

During 2025, 396.4 million ordinary shares were purchased and cancelled. Overall, a total nominal share value of €28 million (\$33 million), 6.5% of the Company's total issued share capital at December 31, 2024, was purchased and cancelled during 2025 for a total cost of \$13.9 billion, including expenses, at an average price of \$35.01 per share.

The buybacks completed in the first half of 2025 were in accordance with the authorities granted by shareholders at the 2024 Annual General Meeting (AGM). The buybacks completed in the second half of 2025 were in accordance with the authorities granted by shareholders at the 2025 AGM. At the 2025 AGM, authority was granted for the Company to repurchase up to a maximum of 10% of its issued ordinary shares, excluding treasury shares, (602.1 million ordinary shares), both on and off market, allowing purchases on the Amsterdam as well as London exchanges. As at December 31, 2025, 444 million ordinary shares could still be repurchased under the current AGM authorities. The purpose of the share repurchases in 2025 was to reduce the issued share capital of the Company.

New resolutions will be proposed at the 2026 AGM to renew the authority for the Company to purchase its own share capital, up to specified limits, for a further year. These proposals will be described in more detail in the 2026 Notice of Annual General Meeting.

Shares are also purchased by the employee share ownership trusts and trust-like entities (see Note 28 to the "Consolidated Financial Statements" on page 299) to meet delivery commitments under employee share plans. All share purchases are made in open market transactions.

The table on the next page provides information on purchases of shares in 2025 and January 2026 by the Company and affiliated purchasers. Purchases in euros and sterling are converted into dollars using the exchange rate on each transaction date.

* Non-GAAP measure. See page 430.

Purchases of equity securities by issuer and affiliated purchasers in 2025 [A]

Purchase period	Euro shares			GBP shares			ADSs [B]	
	Number purchased for employee share plans	Number purchased for cancellation [C]	Weighted average price (\$) [D]	Number purchased for employee share plans	Number purchased for cancellation [C]	Weighted average price (\$) [D]	Number purchased for employee share plans	Weighted average price (\$) [E]
January	5,446,429	13,269,767	32.91	1,271,425	19,923,745	32.68	2,047,363	64.83
February	—	13,818,237	33.48	—	20,965,300	33.28	145,052	67.09
March	—	12,832,246	34.50	—	19,029,647	34.30	19,502	72.38
April	—	13,715,246	32.70	—	20,901,741	32.51	—	—
May	—	18,301,000	33.13	—	17,269,123	32.96	—	—
June	—	16,936,000	35.21	—	17,307,000	35.05	18,967	70.49
July	—	16,369,805	35.71	—	17,188,643	35.55	35,388	70.32
August	—	16,083,942	36.17	—	15,620,239	35.97	—	—
September	3,480,500	17,643,903	36.11	763,300	17,966,650	35.93	19,142	71.88
October	3,105,000	14,970,561	36.77	676,000	15,204,467	36.64	43,971	75.75
November	2,995,123	14,681,496	37.24	664,354	14,716,512	37.14	819,888	74.73
December	—	15,566,925	36.49	—	15,686,468	36.40	865,562	72.94
Total 2025	15,027,052	184,189,128	35.10	3,375,079	211,779,535	34.71	4,014,835	68.95
January	441,451	15,810,185	36.62	159,120	15,915,726	36.53	576,983	74.67
Total 2026	441,451	15,810,185	36.62	159,120	15,915,726	36.53	576,983	74.67

[A] Reported as at transaction date.

[B] American Depositary Shares.

[C] Under the share buyback programme.

[D] Includes stamp duty and brokers' commission.

[E] Includes brokers' commission.

Financial information relating to the Royal Dutch Shell Dividend Access Trust

The results of the Royal Dutch Shell Dividend Access Trust (the Trust) are included in the consolidated results of operations and financial position of Shell. Certain condensed financial information in respect of the Trust is given below.

The Shell Transport and Trading Company Limited and BG Group Limited have each issued a dividend access share to Computershare Trustees (Jersey) Limited (the Trustee). For the years 2025, 2024 and 2023, the Trust recorded income before tax of £nil, £nil and £nil respectively. In each period, this reflected the amount of dividends payable on the dividend access shares. Dividends are also classified as unclaimed where amounts have not cleared recipient bank accounts.

At December 31, 2025, the Trust had total equity of £nil (December 31, 2024: £nil; December 31, 2023: £nil), reflecting assets of £2 million (December 31, 2024: £3 million; December 31, 2023: £4 million) and unclaimed dividends of £2 million (December 31, 2024: £3 million; December 31, 2023: £4 million). The Trust only records a liability for an unclaimed dividend to the extent that dividend cheque payments have not been presented within 12 months, have expired or have been returned unpresented. As these unclaimed dividends relate to dividends that were announced by the Company during the period the Company was still named Royal Dutch Shell plc, and it is expected that the Company will not announce any further dividends on the dividend access shares, the Trust continues to be named the Royal Dutch Shell Dividend Access Trust.

On January 29, 2022, one line of shares was established through assimilation of each A share and each B share into one ordinary share of the Company. This assimilation had no impact on voting rights or dividend entitlements. Dutch withholding tax, applied previously on dividends on A shares, no longer applies on dividends paid on the ordinary shares following the assimilation.

In relation to the assimilation of the Company's A and B shares, the Trust will continue in existence for the foreseeable future to facilitate the payment of unclaimed dividend liabilities for shareholders of the former B shares until these are either claimed or forfeited in line with the terms outlined. Dividends which are unclaimed after six years are forfeited and unconditionally revert to The Shell Transport and Trading Company Limited and BG Group Limited, as appropriate.

Market overview

Shell maintains a large and diversified business portfolio across an integrated value chain. We are exposed to fluctuating prices of crude oil, natural gas, oil products, chemicals and power. However, our diversified portfolio provides resilience when prices are volatile. Our annual planning cycle and periodic portfolio reviews aim to ensure that our levels of capital investment and operating expenses are appropriate in the context of a volatile price environment.

See "Risk factors" on page 126.

We prepare an annual financial plan that tests different scenarios and their impact on prices, and on our businesses and organisation as a whole. These scenarios help us determine which issues could affect our operating environment and have implications for our strategy. They also help us to identify potential interventions to preserve our cash levels.

We continually assess the external environment – the markets and the underlying economic, political, social and environmental drivers that shape them – to evaluate changes in competitive forces. We define multiple potential future scenarios and business environments by identifying drivers, uncertainties, enablers and constraints to our competitiveness.

We also continually screen for new opportunities globally through our opportunity identification process. We test the resilience of our opportunities against a range of prices and costs for crude oil, natural gas, oil products, chemicals and power. These tests are based on short-, medium- and long-term market drivers, such as the extent and pace of the energy transition. Our opportunities are then ranked, prioritised and tested for strategic fit and value return expectations before being included in our growth funnel.

Global economic growth

Global economic disruption and uncertainty characterised 2025. In April of that year, the USA announced a series of broad-based and substantive import tariffs. The USA raised the average effective import tariff from just below 2% at the end of 2024 to around 15% at the end of 2025, triggering trade policy uncertainty. Meanwhile, public spending and debt sustainability concerns emerged for several major economies, as a result of a more stimulative fiscal policy stance or failure to curb public spending.

Despite the disruption and uncertainty, the global economy remained resilient in 2025. Following its initial import tariff announcements, the USA negotiated trade deals with various countries and provided exemptions for certain goods categories. The private sector also proved agile, with companies front-loading imports and re-routing trade flows and supply chains. The potential of AI to boost future productivity and economic growth supported a boom in related investments, including electricity infrastructure and generation. This mitigated some of the downside effects of trade policy uncertainty and public finance concerns. As a result, economic activity remained positive, further enabled by broadly looser monetary and fiscal policies as interest rates fell and fiscal stimulus policies were put in place in many economies.

The IMF, in its World Economic Outlook published in January 2026, estimated global economic growth in 2025 to be 3.3% year on year, equal to the 2024 outcome but below the pre-pandemic average (2000-2019) of 3.7%. Growth in the USA held up at 2.1% – lower than the 2.8% growth recorded the previous year – but with some of the import tariff impact and uncertainty offset by increased investments in AI technologies and related infrastructure. Economic performance in the Eurozone was mixed, with southern Europe more robust as a result of strong private consumption, tourism inflows and EU grants and northern

Europe facing headwinds from loss of industry competitiveness to China, despite higher infrastructure and defence spending. China responded to higher tariffs imposed by the USA by re-routing and redirecting exports to Asia, Africa and Europe, resulting in a record trade surplus. The Chinese government also ratcheted up policy support, although the domestic economy – from the housing sector to retail sales – disappointed. Emerging economies benefited from lower interest rates, depreciation of the US dollar and improving policy frameworks – such as greater exchange rate flexibility – which enhanced their capacity to absorb shocks. Among the emerging economies, India continued to lead, thanks to strong household consumption and company investment.

Global consumer price growth was generally contained as declines in emerging markets' inflation offset a slight goods-driven pick-up in inflation in advanced economies. But, in many countries, the cost of living in 2025 was significantly higher than before the pandemic. In the USA, firms accumulated inventories during the first half of 2025 as a result of tariff front-running, allowing them to delay price increases. Inflation cooled in the Eurozone, although wage pressures and services inflation remained persistent. In China, consumer price inflation remained at very low levels, stemming from overcapacity in industry, weakness in the housing sector, and relatively high savings.

Global prices, demand and supply

The following table provides an overview of the main crude oil and natural gas price markers to which Shell is exposed.

Oil and gas average industry prices [A]

	2025	2024	2023
Brent (\$/b)	69.1	80.8	82.6
West Texas Intermediate (\$/b)	64.9	75.9	77.7
Henry Hub (\$/MMBtu)	3.5	2.2	2.5
EU TTF (\$/MMBtu)	11.9	11.0	13.0
Japan Customs-cleared Crude (\$/b) - 3 months	76.1	87.5	88.7

[A] The 2025 average price for Japan Customs-cleared Crude is based on available market information up to the end of the period. Brent, West Texas Intermediate and EU TTF yearly average prices are based on daily spot prices. Henry Hub and Japan Customs-cleared Crude yearly average prices are based on monthly average prices.

At the time of this Report's publication, world energy markets were being impacted by conflict in the Middle East. It was still highly uncertain as to the extent and longevity of disruption to infrastructure, LNG and oil flows through the Strait of Hormuz, as well as to risks of interruption to supply.

Crude oil and oil products

The global benchmark oil price Brent averaged \$69 per barrel (bbl) in 2025, considerably lower than the average of \$81/bbl in 2024. Downside risks to oil markets increased sharply from early April 2025 after the US tariff announcements and the OPEC+ decision to accelerate the unwinding of voluntary production cuts. Following the US tariff announcement, Brent dropped by over \$10/bbl to touch a four-year low of just above \$60/bbl in early May 2025. The downward trend was briefly arrested when Brent reached a six-month high of \$80/bbl at the height of the 12-day war between Israel and Iran in June 2025. As this subsided, the bearish price trend returned over market expectation for significant oversupply due to the rapid unwinding of OPEC+ production curtailment.

Global liquids demand growth in 2025 was estimated at around 0.9 million barrels per day (mb/d), slightly slower than in 2024. Chinese demand remained sluggish, increasing by only about 0.1 mb/d, compared with 0.15 mb/d in 2024. Other major markets – OECD Americas, OECD Europe and non-OECD Asia (excluding China) – also saw weaker growth. Nonetheless, supply surged in 2025 due

to the rapid return of OPEC+ curtailed volumes. Since OPEC+ started unwinding the voluntary cuts in April 2025, total global liquids supply rose by 4.6 mb/d by the third quarter. This caused a sharp increase in global liquids inventory in the second half of 2025. The IEA reported an implied global stock build of 3 mb/d in the third quarter of 2025, compared with a net draw of 0.8 mb/d in the same period of 2024.

In 2026, market direction will depend on how certain key drivers evolve: Chinese demand, OPEC+ supply strategy, the production outlook of US light tight oil (LTO), and geopolitical developments in the Middle East, Russia/Ukraine, and Venezuela. The IEA expects a slightly higher growth rate for global demand as Chinese oil demand growth picks up slightly. On the supply side, US LTO responded to falling oil prices with much more moderate production growth in 2025, and the trend could continue should oil prices remain depressed. OPEC+ paused the unwinding in the first quarter of 2026, but decided to resume in April 2026.

Natural gas market

Global gas prices increased in 2025 as Europe imported more LNG to offset the loss of Russian gas transiting through Ukraine. Prices remained above historic levels seen prior to 2022. Market volatility persisted due to concerns about security of supply in Europe, despite additional LNG from the USA. However, subdued LNG imports into China had a negative impact on prices.

In Europe, TTF (Title Transfer Facility) spot prices averaged \$12.12/MMBtu (11% higher year-on-year) with the loss of Russian pipeline gas via the Ukrainian transit route on January 1, 2025. Nonetheless, European gas demand remained weak throughout the year, driven by a warm winter, continued lower industrial demand and high renewable power generation. Storage levels comfortably reached the EU mandatory targets by October 2025. Prices softened further in the fourth quarter as additional LNG supplies and weaker Asian demand supported more LNG flows into Europe.

Spot LNG prices in Asia traded closely in line with TTF for much of 2025, reflecting the growing interconnection of global LNG markets. JKM (Japan/Korea Marker) prices averaged \$12.37/MMBtu (4% higher year on year). Through the first three quarters, JKM prices held negligible premiums over TTF as declines in Chinese demand failed to attract significant cargoes to Asia. In the fourth quarter, with higher Asian storage levels, JKM fell below \$10/MMBtu, stimulating additional demand and incentivising some LNG flows to Asia.

Henry Hub: In 2025, natural gas production in the USA averaged 106.5 billion cubic feet per day (Bcf/d) for the year, up from 101.7 Bcf/d in 2024, with most of the year-over-year growth concentrated in the South Central region, particularly the Permian Basin. Production reached a record high of 111.4 Bcf/d on December 21, 2025. On the demand side, gas used for power generation has averaged 35.7 Bcf/d, which is 1.1 Bcf/d lower than last year. This decline is primarily due to increased renewable and coal generation. While the Lower 48 experienced cooler temperatures – averaging 14.6°C compared with 15.3°C in 2024 – any potential increase in winter heating demand was more than offset by reduced power generation demand during the milder summer. Meanwhile, LNG exports are expected to rise by 3.5 Bcf/d year on year, driven largely by the ramp-up of the Plaquemines LNG facility, reinforcing the USA's growing role in global gas markets.

Power

USA: In 2025, power markets experienced mixed regional dynamics shaped by capacity tightness in the east, strong renewable and storage growth across multiple regions, and mild weather in Texas and the West. PJM Interconnection saw capacity prices surge to historic highs, with Base Residual Auction clearing prices rising nearly 10-fold year on year and further reaching the market cap for 2026/27, reflecting tightening supply conditions and higher reliability requirements. New York Independent System Operator (NYISO) and New England Independent System Operator (ISO-NE) also faced shrinking reliability margins, i.e. system safety buffers. This was driven by fossil retirements, growing large-load interconnections from data centres and semiconductor facilities, and heightened winter fuel supply risks. In Texas, the Electric Reliability Council of Texas (ERCOT) market saw mild summer weather and strong solar growth that kept daytime conditions stable, even as higher thermal outages increased reliance on energy storage. Real-time power prices were slightly higher than in 2024 due to increased natural gas costs. A major structural development occurred late in the year with the launch of ERCOT's Real-Time Co-Optimization plus Batteries (RTC-B) framework in December 2025, marking the beginning of ERCOT's transition to a more modern real-time market design. In the Western USA, power prices stayed muted throughout most of 2025, with only a few brief price excursions above \$100/MWh in the Pacific Northwest. Large additions of solar, wind and battery capacity – amounting to around 7 GW of renewables and 7.2 GW of storage – helped maintain system flexibility despite lower hydropower generation. Across the country, solar, wind and battery storage continued to expand rapidly and increasingly shaped hourly price profiles. Demand growth from data centres, AI compute clusters and electrification remained a major demand driver in 2025 and is expected to continue driving infrastructure needs and resource additions into 2026.

Europe: Across Europe, power prices rebounded slightly from 2024. In the first half of the year, higher gas prices and cold, calm weather caused an increase of 20–30 EUR/MWh in the major markets of Germany, France, the UK and Spain. Lower base-load prices in the second half of the year brought the annual average increase to 4.11 EUR/MWh compared with 2024. German power prices are still among the highest on the continent with an annual average of 89 EUR/MWh. Unprecedented voltage spikes and operational failures in the Iberian grid caused Europe's largest blackout in two decades, triggering 31 GW of load to be disconnected and leading to the deaths of seven people. France connected its first new nuclear reactor in 25 years, while Belgium extended the lifetime of existing nuclear reactors. Meanwhile, solar installations in the EU declined for the first time in a decade, down 1.4% at mid-year from 2024's record high. Offshore wind faced difficulties as Dutch and Danish tenders closed without bids, prompting Denmark to announce a shift to a two-sided contract for difference (CFD) model. In contrast, Germany held oversubscribed onshore wind auctions. The German government still plans to hold auctions next year for new gas-fired power plants with a combined capacity of 10 GW by 2032.

Australia: Electricity volume-weighted average prices (VWAP) on the east coast National Electricity Market (NEM) were around A\$107.72/MWh in 2025, decreasing from around A\$131.22/MWh in 2024. Conversely, the west coast Wholesale Electricity Market (WEM) saw an increase in VWAP from around A\$92.93/MWh to around A\$114.74/MWh. This was partly due to a slight decline in domestic gas prices. Overall the NEM saw milder conditions than in the previous year, with the exception of a few days in June which saw extreme volatility as a result of coal outages, low wind generation and increased demand due to colder weather. Looking to the year ahead, the first tranche of the government's Capacity Investment Scheme (CIS) projects are expected to start operations, representing a new wave of wind, solar and storage assets in the NEM and WEM. Concurrently, the government has commenced a gas market review on Australia's east coast domestic gas and LNG export markets, with work ongoing through 2026.

Crude oil and natural gas price assumptions

Our ability to deliver competitive returns and pursue commercial opportunities depends on the accuracy of our price assumptions. We use a rigorous assessment of short-, medium- and long-term market uncertainties to determine which ranges of future crude oil and natural gas prices to use in project and portfolio evaluations. Market uncertainties include, for example, future economic conditions, geopolitics, actions by major resource holders, production costs, technological progress and the balance of supply and demand.

See "Risk factors" on page 126 and Note 12 to the "Consolidated Financial Statements" on pages 269-270.

Refining and chemical margins

After a weak start to 2025, refinery margins improved versus 2024, mainly because sanctions on Russia affected middle distillate supply and third and fourth quarter refinery availability was lower. Gasoline product crack spreads started the year at a low level, as increasing refinery capacity, particularly with Dangote Refinery in Nigeria ramping up, promised higher gasoline supply. Middle distillate crack spreads started 2025 stronger than gasoline but supply chains were working well which kept prices at reasonable levels. In the second half of 2025, Dangote started to have reliability issues resulting in more gasoline demand in West Africa from Europe. This, combined with refinery outages in the USA, resulted in support for gasoline product crack spreads. Middle distillate supply has been affected by Ukrainian drone strikes on Russian infrastructure, reducing middle distillate exports; in addition, the sanctions against Lukoil and Rosneft brought in during the final quarter of 2025, combined with general low refinery availability, created middle distillate supply concerns and high product crack spreads.

The 2026 margin outlook depends on refinery availability, particularly in the Atlantic Basin, and on whether the new refineries such as Olmeca in Mexico and Dangote in Nigeria achieve full capacity. Also to be watched is potential sanction relief on Russia that could bring significant quantities of product to international markets.

Chemical margins remained under pressure in 2025 due to continued growth of excess capacity in China. China added 7 million tonnes (MMTA) ethylene capacity while global demand grew by only 4 MMTA. In Europe, continued high costs, the loss of competitive exports (since 2022), and increasing low-cost imports have triggered announcements for an additional 3 MMTA ethylene capacity closure from 2025 to 2027. In the USA, cracker utilisation remains healthy due to low-cost feedstock (ethane).

Shell Chemicals global weighted average indicative margin declined by about 30 \$/t in 2025 from 2024. Most of the margin drop was observed in the USA, where the ethane cracking advantage eroded with falling crude and rising natural gas prices. Crude prices declined by \$10/bbl while Henry Hub gas prices increased by \$1.3/MMBtu. Note that global chemicals prices tend to follow the crude price, while US ethane price follows local natural gas. A second driver for weaker US chemicals margins was the declining propylene price as the market corrected due to improved supply and stagnant demand. Propylene prices declined by about 220 \$/t from 2024 to 2025.

China continues to add capacity in 2026, which should keep Asia chemicals variable margins near zero. The business expects that Shell's global indicative chemicals margin will improve slightly in 2026 due to strengthening prices in the USA and Europe. In Europe, recent industry rationalisation is expected to support market ethylene and propylene prices.

Refining margins

Global indicative refining margin

	2025	2024	2023
Indicative refining margin	10.14	7.74	12.45

\$/bbl

The indicative refining margin is an approximation of Shell's global gross refining unit margin, calculated using price markers from third-party databases. It is based on a simplified crude and product yield profile at a nominal level of refining performance. The actual margins realised by Shell may vary due to factors including specific local market effects, refinery maintenance, crude diet optimisation as the crudes in the indicative refining margin are indicative benchmark crudes, operating decisions and product demand. Gross refining unit margin is defined as the hydrocarbon margin net of purchased/sold utilities, additives and relevant freight costs, divided by crude and feedstock intake in barrels. It is only applicable to the impact of market pricing on refining business performance, excluding trading margin.

Petrochemical margins

Global indicative chemical margin

	2025	2024	2023
Indicative chemical margin	147.9	151.72	132.63

\$/tonne

The indicative chemical margin (ICM) is an approximation of Shell's global chemical margin performance trend (including equity-accounted associates), calculated using price markers from third-party databases. It is based on a simplified feedstock and product yield profile at a nominal level of plant performance. The actual margins realised by Shell may vary due to factors including specific local market effects, chemical plants maintenance, optimisation, operating decisions and product demand. Chemical unit margin is defined as the hydrocarbon margin net of purchased/sold utilities, additives and relevant freight costs, divided by a nominal denominator expressed in tonnes. It is only applicable to the impact of market pricing on Chemicals business performance.

The statements in this "Market overview" section are forward-looking statements based on management's current expectations and certain material assumptions and, accordingly, involve risks and uncertainties that could cause actual results, performance or events to differ materially from those expressed or implied herein.

See "About this Report" on pages v-vi and "Risk factors" on page 126.



Integrated Gas

Integrated Gas explores for and extracts natural gas and associated liquids. This gas is then processed to produce liquefied natural gas (LNG) or converted into gas-to-liquids (GTL) fuels and other products. The business includes the operation of both upstream and midstream infrastructure necessary to deliver natural gas and its derivatives to market.

At Capital Markets Day 2025, we said we would reinforce our leadership position in LNG by growing sales by 4–5% per year [A] through to 2030. We will also grow top-line production across our combined Upstream and Integrated Gas business by 1% per year [A] to 2030, sustaining our 1.4 million barrels per day of liquids production to 2030 with increasingly lower carbon intensity.

In 2025, our performance and robust CFFO generation were driven by portfolio growth and operational excellence, with LNG sales growing by 11%, supported by the highest number of cargoes delivered in a single year.

This record was supported by the acquisition of Pavilion Energy which increased our access to third-party volumes. We also began production at LNG Canada and shipped the first cargoes from there, marking a significant milestone in our integrated gas strategy. LNG Canada, which holds a 40-year export licence, expands Shell's global LNG portfolio, which is already one of the largest in the world.

Final investment decisions taken in the year on the Mina West project in Egypt, the Aphrodite project in Trinidad and Tobago and the Gorgon Stage 3 development in Australia will help to secure future supply and contribute towards meeting our annual growth targets.

For the business conditions relevant to Integrated Gas, see "Market overview" on pages 25-27.

[A] On a compound annual growth rate (CAGR) basis.

8.8

Income/(loss) for the period (\$ billion)
(2024: 9.6)

8.0

Adjusted Earnings (\$ billion)
(2024: 11.4)

14.1

Cash flow from operating activities (\$ billion)
(2024: 16.9)

931

Production (thousand boe/d)
(2024: 954)

28

LNG liquefaction volumes (million tonnes)
(2024: 29)

73

LNG sales volumes (million tonnes)
(2024: 66)



"This was a year of strong, competitive delivery and cash outcomes, laying a solid foundation for us to be the world's leading integrated gas and LNG business."

Cederic Cremers
President, Integrated Gas

Financial delivery

2025 earnings [A]

Income/(loss) for the period was driven by the same factors as Adjusted Earnings and includes identified items.

Adjusted Earnings decreased by \$3,366 million compared with 2024. This reflected the combined effect of lower contributions from trading and optimisation and lower realised prices (a decrease of \$3,034 million), higher depreciation, depletion and amortisation expenses (increase of \$407 million), and lower volumes (decrease of \$250 million). This was partly offset by lower well write-offs (decrease of \$252 million), and favourable tax movements (\$102 million).

Identified items in 2025 included favourable movements of \$1,171 million due to the fair value accounting of commodity derivatives, partly offset by impairment charges of \$433 million. These favourable movements and charges are part of identified items and compare with the full year 2024 which included unfavourable movements of \$1,088 million due to the fair value accounting of commodity derivatives, impairment charges of \$363 million, and a net loss of \$96 million related to the sale of assets. As part of Shell's normal business, commodity derivative contracts are entered into as hedges for mitigation of economic exposures on future purchases, sales and inventory.

Adjusted EBITDA was driven by the same factors as Adjusted Earnings.

Prior year earnings [A]

Income/(loss) for the period was driven by the same factors as Adjusted Earnings and includes identified items.

Adjusted Earnings decreased by \$2,529 million compared with 2023. This reflected the combined effect of lower contributions from trading and optimisation and lower realised prices (a decrease of \$3,819 million). This was partly offset by higher volumes (an increase of \$514 million), lower operating expenses (a decrease of \$478 million), and favourable deferred tax movements (\$399 million).

Identified items in 2024 included unfavourable movements of \$1,088 million relating to an accounting mismatch due to fair value accounting of commodity derivatives, impairment charges of \$363 million, and a net loss of \$96 million related to the sale of assets. These unfavourable movements compare with 2023, which included unfavourable movements of \$4,407 million due to the fair value accounting of commodity derivatives, and net impairment charges and reversals of \$2,247 million. As part of Shell's normal business, commodity derivative hedge contracts are entered into for mitigation of economic exposures on future purchases, sales and inventory.

Adjusted EBITDA was driven by the same factors as Adjusted Earnings.

Cash flow from operating activities

Cash flow from operating activities for 2025 was primarily driven by Adjusted EBITDA and net cash inflows related to derivatives of \$1,487 million. These inflows were partly offset by tax payments of \$3,261 million and working capital outflows of \$835 million.

Shell's policy is to settle the inter-segment use of tax attributes between business segments. This settlement is usually made in cash but in certain instances there is no cash settlement. In 2025, deferred tax assets of the Integrated Gas (\$211 million) and Corporate (\$89 million) segments were used by the Chemicals and Products (\$300 million) segment, for which no cash settlement was made.

Key metrics [B]

\$ million, except where indicated

	2025	2024	2023
Income/(loss) for the period	8,820	9,590	7,057
Identified items [B]	796	(1,800)	(6,862)
Adjusted Earnings* [B] [C]	8,024	11,390	13,919
Adjusted EBITDA* [C] [D]	16,994	20,978	23,773
Cash flow from operating activities	14,086	16,909	17,520
Cash capital expenditure*	4,689	4,767	4,196
Liquids production available for sale (thousand b/d)	128	132	128
Natural gas production available for sale (million scf/d)	4,654	4,769	4,700
Total production available for sale (thousand boe/d)	931	954	939
LNG liquefaction volumes (million tonnes)	28.4	29.1	28.3
LNG sales volumes (million tonnes)	72.9	65.8	67.1

[B] See Note 7 to the "Consolidated Financial Statements" on pages 259-267.

[C] Adjusted Earnings and Adjusted EBITDA are presented on a current cost of supplies basis.

[D] Adjusted EBITDA is without taxation, exploration well write-offs and depreciation, depletion and amortisation (DD&A) expenses.

Cash capital expenditure

Our cash capital expenditure in 2025 was lower than in 2024. The decrease was mainly a result of a major turnaround at Pearl GTL in 2024. Our cash capital expenditure* is expected to be around \$6 billion in 2026 in Integrated Gas.

Operational performance

Production available for sale

Our natural gas production decreased by 2% in 2025 compared with 2024, mainly due to natural field decline across the portfolio. In 2025, natural gas and liquids made up 86% and 14% of total production, respectively.

LNG liquefaction and sales volumes

Our LNG liquefaction volumes decreased by 2% compared with the previous year. This was mainly due to ownership restructuring in Trinidad and Tobago, and higher maintenance across the portfolio, and was partly offset by the LNG Canada ramp-up.

LNG sales volumes increased in 2025 compared with 2024, primarily due to higher purchases from third parties following the Pavilion Energy acquisition.

[A] All earnings amounts are shown post-tax unless otherwise stated.

* Non-GAAP measure. See page 430.

Integrated Gas data table

LNG liquefaction volumes

	Million tonnes		
	2025	2024	2023
Australia	13.3	14.4	13.3
Brunei	1.2	1.2	1.1
Canada	0.9	—	—
Egypt	0.1	—	0.3
Nigeria	3.7	3.5	3.3
Oman	2.8	2.8	2.7
Peru	0.8	0.9	0.8
Qatar	2.4	2.3	2.4
Trinidad and Tobago	3.2	4.0	4.3
Total	28.4	29.1	28.3

Strategic progress

Portfolio and business developments

Significant portfolio and business developments:

- In March 2025, we completed the acquisition of 100% of the shares in Pavilion Energy Pte. Ltd. (Pavilion Energy). The deal was announced in June 2024.
- In June 2025, the first cargo of LNG left the LNG Canada joint venture facility (Shell interest 40%).
- In June 2025, a final investment decision (FID) was taken to start the development of and production at the Mina West gas discovery in Egypt (Shell interest 60%).
- In June 2025, an FID was taken on the Aphrodite development project in Trinidad and Tobago (Shell interest 100%).
- In December 2025, an FID was taken on the Gorgon Stage 3 development in Australia (Shell interest 25%).

Business and property

Integrated Gas

A complete list of LNG and GTL plants in operation and under construction in which we have an interest is provided below.

LNG liquefaction plants under construction at December 31, 2025

	Asset	Location	Shell interest (%)	100% capacity (mtpa) [A]	Shell-operated
Africa					
Nigeria	Train 7 [B]	Bonny	25.6	7.6	No
Asia					
Qatar	QatarEnergy LNG NFE(2) [C]	Ras Laffan	25.0	8.0	No
	QatarEnergy LNG NFS(2) [D]	Ras Laffan	25.0	6.0	No
United Arab Emirates	Ruwais LNG [E]	Al Ruwais	10.0	9.6	No

[A] 100% capacity represents the total capacity that all trains are expected to process as reported by the operator.

[B] First LNG is expected in the second half of the 2020s.

[C] Shell holds 25% in the joint venture, which owns 25% of the North Field East expansion project, which has a nameplate capacity of 32 mtpa. First LNG is expected in the second half of the 2020s.

[D] Shell holds 25% in the joint venture, which owns 37.5% of the North Field South expansion project, which has a nameplate capacity of 16 mtpa. First LNG is expected in the second half of the 2020s.

[E] First LNG is expected in 2028.



Making the most of our existing assets

In 2025, across our Integrated Gas portfolio, we reached final investment decisions and key milestones that demonstrate how we are maximising value by investing in gas discoveries to keep our high utilisation of existing assets.

We are leveraging established infrastructure to help unlock value for Shell and contribute to the strengthening of energy security in key markets.

Strengthening Trinidad and Tobago's gas future

In Trinidad and Tobago, the Atlantic LNG facility is a significant supplier of LNG for the export market. Shell's interests in the production trains range from 47.15% to 51.1%. We also have interests in two concessions with producing fields: North Coast Marine Area (Shell interest 80.5%) and East Coast Marine Area (Shell interest 100%) – both are already home to some of Shell's largest gas producing fields.

We took a final investment decision (FID) in July 2024 to develop the Manatee gas field and in 2025 we took an FID on the Aphrodite backfill project development [A]. Aphrodite, together with Manatee, will help sustain Trinidad and Tobago's gas industry into the 2030s.

Aphrodite will connect to existing subsea infrastructure in the Shell Operated East Coast Marine Area, sending gas to the Dolphin A platform. Production is expected to start in 2027 and reach a peak production capacity of about 18,400 boe/d. Manatee is also expected to deliver first gas in 2027 and reach a peak production capacity of 104,000 boe/d.

Accelerated delivery in Egypt

Gas was discovered in Egypt's Mina West field in October 2023, and we and our partners took an FID in June 2025 to start development and production. This demonstrates how partnership and accelerated project execution offer an opportunity to unlock value quickly.

Mina West will be developed as a subsea tieback to the existing West Delta Deep Marine (WDDM) concession infrastructure which supplies gas to the domestic market and the Egyptian LNG plant. WDDM (Shell interest 50%) is operated by the Burullus Gas Company joint venture (Shell interest 25%) and supplies gas to the domestic market and an Egyptian LNG plant.

Shell will operate the Mina West field with a 60% interest. The project is expected to deliver secure, reliable energy to the domestic market while expanding Shell's gas business.

Efficient execution in Australia

In 2025, the Crux platform jacket was installed offshore Western Australia. The project shows the advantages of re-engaging contractors and fabrication yards to help reduce execution risk. The platform will supply backfill gas to the Prelude FLNG facility from the Crux field, 160 kilometres north-east of Prelude. Crux will be operated remotely from Prelude.

The Phase 1 drilling campaign delivered five wells and was completed in 2025, finishing 78 days ahead of schedule and delivering cost savings. Subsea pipelay activities were also executed efficiently, completing three months early.

An FID was also taken on the Gorgon Stage 3 backfill development project. This will connect the offshore Geryon and Eurytion natural gas fields in the Greater Gorgon Area to Gorgon's existing subsea gas gathering infrastructure and processing facilities on Barrow Island. The development will help maintain production at Gorgon, enabling the long-term supply of domestic gas for Western Australian households and industry, and LNG for international customers.

1. The Crux jacket being installed at the Crux site in Western Australia.

[A] The Aphrodite project is pending regulatory approvals.

LNG liquefaction plants in operation at December 31, 2025 [A]

	Asset	Location	Shell interest (%)	100% capacity (mtpa) [B]	Shell-operated
Asia					
Brunei	Brunei LNG	Lumut	25	7.6	No
Oman	Oman LNG	Sur	30	7.1	No
	Qalhat LNG [C]	Sur	11	3.7	No
Qatar	QatarEnergy LNG N(4) [D]	Ras Laffan	30	7.8	No
Oceania					
Australia	North West Shelf [D]	Karratha	16.7	14.3	No
	Gorgon LNG [D]	Barrow Island	25	15.6	No
	Prelude [D]	Browse Basin	67.5	3.6	Yes
	Queensland Curtis LNG T1 [D]	Curtis Island	50	4.3	Yes
	Queensland Curtis LNG T2 [D]	Curtis Island	97.5	4.3	Yes
Africa					
Egypt	Egyptian LNG T1	Idku	35.5	3.6	No
	Egyptian LNG T2	Idku	38	3.6	No
Nigeria	Nigeria LNG T1-T6	Bonny	25.6	24.1	No
North America					
Canada	LNG Canada T1-2 [E]	Kitimat	40.0	14.0	No
South America					
Peru	Peru LNG	Pampa Melchorita	20	4.5	No
Trinidad and Tobago	Atlantic LNG T1/2/3	Point Fortin	47.15	9.3	No
	Atlantic LNG T4	Point Fortin	51.1	5.2	No

[A] We have offtake rights via a lease to 100% of the capacity (2.5 mtpa) of the Kinder Morgan-operated Elba Island liquefaction plant in Georgia, USA.

[B] 100% capacity represents the total capacity that all trains can process as reported by the operator.

[C] The interest is held via an indirect shareholding through Oman LNG.

[D] These assets are clustered as integrated assets and have onshore or offshore upstream production.

[E] The first cargo left LNG Canada in June 2025.

GTL plants in operation at December 31, 2025

	Asset	Location	Shell interest (%)	100% capacity (b/d) [A]	Shell-operated
Asia					
Malaysia	Shell MDS	Bintulu	72.0	14,700	Yes
Qatar	Pearl	Ras Laffan	100.0	140,000	Yes

[A] 100% capacity represents the total capacity of the plant.

LNG regasification terminals

As at December 31, 2025 we held interests in the following regasification terminals:

- Dragon LNG in the UK (Shell interest 50%);
- Shell Energy India (Shell interest 100%); and
- Shell LNG Gibraltar (Shell interest 51%).

We had rights in other regasification terminals in:

- the Netherlands (Shell capacity rights 4.6 mtpa);
- the UK (Shell capacity rights 2 mtpa);
- the USA (total Shell capacity rights 24.7 mtpa);
- Mexico (Shell capacity rights 2.7 mtpa); and
- Singapore (mainly licences to import LNG and sell regasified LNG in Singapore with no volume cap).

Total Shell regasification capacity rights were 9.7 mtpa in Europe, 27.4 mtpa in North America and 6 mtpa in Asia.

Oil and natural gas production, exploration and development

The contractual frameworks most relevant to our activities are set out on page 42.

Australia

We operate the Queensland Curtis LNG (QCLNG) venture's natural gas operations in the onshore Surat Basin. Our interests range from 44% to 74% in 25 field compression stations and six central processing plants. Gas from the Surat Basin is supplied to the QCLNG liquefaction plant and the domestic gas market. Also in Queensland, we have a 50% interest in the Arrow joint venture with China National Petroleum Corporation (CNPC). Arrow owns coalbed methane assets and a domestic power business.

Shell has interests in offshore production, LNG liquefaction and exploration licences in the Browse Basin, and in the North West Shelf (NWS) and Greater Gorgon areas of the Carnarvon Basin. Woodside operates the NWS joint venture (Shell interest 16.7%). We have a 25% interest in the Chevron-operated Gorgon LNG joint venture that includes offshore production. In December 2025, we took an FID on the Gorgon Stage 3 development project. In the Browse Basin, Shell operates the Prelude field (Shell interest 67.5%) and the Crux gas and condensate development field (Shell interest 84.5%).

Bolivia

We have a 37.5% interest in the Repsol-operated Caipipendi block where natural gas is produced and delivered to domestic and export markets. We also have a 25% interest in the Tarija XX West block which produces from the Itaú field.

Canada

We produce and market natural gas, natural gas liquids and condensate. We hold mineral acres, primarily in the Montney play in British Columbia and Alberta. We operate four natural gas processing facilities at our Groundbirch asset in British Columbia. Shell's working interest across the Groundbirch acreage ranges from 88% to 92%. Gas from the Groundbirch asset is supplied to the LNG Canada Shell-operated liquefaction plant and domestic gas market. Shell has a 40% interest in LNG Canada which is a joint venture with Petronas, PetroChina, Mitsubishi and Kogas. In June 2025, the first cargo of LNG left the facility.

China

We develop and produce from the onshore Changbei tight-gas field under a PSC with China National Petroleum Corporation.

Egypt

We have a range of venture and concession interests. The Burullus Gas Company joint venture (Shell interest 25%) operates the West Delta Deep Marine concession (Shell interest 50%) and supplies gas to the domestic market and an Egyptian LNG plant. The Rashid Petroleum Company (Rashpetco) joint venture (Shell interest 50%) operates the Rosetta concession (Shell interest 100%). The El Burg Offshore Company (EBOC) joint venture (Shell interest 30%) operates the El Burg offshore concession (Shell interest 60%). A sales and purchase agreement (SPA) has been signed for the El Burg concession to divest 100% of Shell interest to Arcius and this was completed in February 2026. The Mina Gas Company (Mina Gas) joint venture (Shell interest 30%) operates the Northeast El Amriya offshore concession (Shell interest 60%). In June 2025, a final investment decision was taken to start development and production from the Mina West gas discovery.

We also have interests in several exploration concessions in the Nile Delta and the wider East Mediterranean.

Oman

We have a concession agreement for the development and production of natural gas and condensate in the Shell-operated Block 10 (Shell interest 53.45%). We also have an exploration and production-sharing agreement for the exploration and appraisal of natural gas and condensate in the Shell-operated Block 11 (Shell interest 67.5%). Since January 2025, we have had a long-term offtake agreement in place to purchase up to 1.6 mtpa over a 10-year period from Oman LNG.

Qatar

Under a development and production-sharing contract with the government, we operate the fully integrated Pearl GTL plant (Shell interest 100%) and associated upstream production. Pearl GTL has the capacity to produce, process and transport 1.6 billion standard cubic feet per day (scf/d) of gas from Qatar's North Field.

We have a 30% interest in QatarEnergy LNG N(4), an integrated onshore gas-processing facility operated by QatarEnergy LNG, which can produce around 1.4 billion scf/d of gas from Qatar's North Field. We also have a 25% interest in the QatarEnergy LNG NFE(2) joint venture, which owns a 25% interest in the North Field East (NFE) project. Shell's ownership of NFE via the joint venture is 6.25%. In addition, we have a 25% interest in the QatarEnergy LNG NFS(2) joint venture which owns a 37.5% interest in the North Field South (NFS) project. Shell's ownership of NFS via the joint venture is 9.375%.

Russia

In 2022, Shell announced its intent to withdraw in a phased manner from its involvement in all Russian hydrocarbons, including crude oil, petroleum products, gas and LNG. Shell still holds a 27.5% (minus one share) interest in Sakhalin Energy Investment Company Ltd. (SEIC), a Bermudan entity, which purportedly no longer holds any licences, rights and obligations in Sakhalin-2. Shell still holds one long-term LNG purchase contract with a Novatek entity.

Trinidad and Tobago

We have interests in two concessions with producing fields: North Coast Marine Area (Shell interest 80.5%) and East Coast Marine Area (Shell interest 100%), where in June 2025 we took a final investment decision on the Aphrodite development project.

In May 2025, we completed the sale of our 65% interest in the Central Block facility to Touchstone Exploration Trinidad Limited.

We have a 100% interest in exploration blocks 5(c)REA, 6d and modified block U(c). We also have a 50% interest in exploration blocks 25a, 25b and 27 in the Columbus Basin. We operate Block 27 and bp is the operator of the remaining two. In 2025, we submitted notification of our relinquishment of all portions of the Block 5d contract area.

Other

We also have interests in Barbados, Colombia (withdrawal is in progress), Cyprus, Tanzania and Venezuela [A].

[A] Our previous Office of Foreign Assets Control (OFAC) licence was withdrawn in 2025 in line with US policy at the time, meaning that we have been unable to undertake any activities related to our Venezuela interest since then. In mid-February 2026, the USA issued several general licences that authorise various activities in Venezuela, including one that allows certain companies to engage in oil and gas operations in Venezuela and produce from its reserves. We are currently reviewing these general licences to understand how they impact our activities.

Trading and Optimisation

Our trading organisation markets and sells our share of equity production of LNG and third-party LNG through our UK, UAE and Singapore trading hubs. We have term sales contracts for most of our LNG liquefaction and term purchase contracts. Our shipping network, regasification terminals and ability to buy and deliver spot cargoes from third parties enable us to optimise the income we generate from our LNG cargoes. For example, if a customer no longer needs a scheduled cargo, we can deliver it to another customer. Similarly, if a customer needs an additional cargo not available from our own production, we contract with third parties to deliver that cargo. We conduct paper trades, primarily to manage commodity price risk related to sales and purchase contracts.

1.



LNG Canada makes its first shipments to Asia

On June 30, 2025, the first shipment of LNG left the LNG Canada joint venture facility in British Columbia for Asia, where it will help to meet the region's growing demand for natural gas.

Shell is involved across the LNG value chain, from extraction and liquefaction to shipping, trading, regasification and delivery. The LNG Canada value chain is a key example of this. LNG Canada, which holds a 40-year export licence, expands Shell's global LNG portfolio, which is already one of the largest in the world.

Sourcing and liquefying the gas

As a shareholder in LNG Canada, Shell sources gas from third parties on the open market and from our own Groundbirch asset in British Columbia. Natural gas is extracted at Groundbirch using advanced technologies to unlock the gas safely and responsibly. After being extracted and processed at our local gas plants, the natural gas is funnelled into the Coastal GasLink pipeline. This pipeline is 670 kilometres long and crosses two mountain ranges to reach LNG Canada at Kitimat on a remote part of the Pacific coast.

In Kitimat, the gas is turned into LNG to make it more efficient to store and ship. The gas is cooled to -162°C , reducing its volume by about 600 times. LNG Canada has two processing units, or "trains", which have the collective capacity to produce 14 million tonnes of LNG a year. This is enough to meet the annual natural gas requirements of Singapore and Vietnam combined in 2024. Four gas turbines – derived from aircraft engines and used in an LNG plant for the first time – power the liquefaction process.

Supplying Asia

The LNG is loaded onto ships and transported to global markets, mainly in Asia. LNG Canada halves shipment times to Asian markets compared with cargoes from the Gulf of America, which must pass through the Panama Canal, a potential choke point, to reach the Pacific Ocean and Asia.

Exactly where the cargoes from LNG Canada end up depends on Shell's trading teams. Some customers enter into long-term contracts that extend beyond 10 years, while others purchase single cargoes just days before delivery.

Shell's traders analyse weather patterns, economic trends, supply and demand, and geopolitical events. At Shell, our ability to navigate these complex and dynamic markets is key to helping to meet global energy demand.

Putting Canada, and LNG, on the energy map

LNG Canada is among the largest private-sector investments in Canada's history and the country's first large-scale LNG export facility. LNG Canada was designed to be one of the lowest-carbon-intensity LNG facilities in the world.

Shell is the largest owner in LNG Canada, holding a 40% interest. The other joint venture partners include PETRONAS of Malaysia, PetroChina, Mitsubishi Corporation of Japan, and Korea Gas Corporation, all based in recipient markets in Asia.

More than 50,000 Canadians have directly contributed to building LNG Canada and to date more than CAN \$5.8 billion in contracts and subcontracts have been awarded to local, Indigenous and other businesses in British Columbia [A].

Shell's 2025 LNG Outlook forecasts global demand for LNG to rise by around 60% by 2040, largely driven by economic growth in Asia.

Gas, including LNG, is a stabilising force in energy systems because it is versatile, flexible and reliable. Gas is versatile because it can be used in power generation, industry, heating and transport. It is also flexible and reliable because it is simple to deploy and can be shipped, as LNG, to where it is needed to meet changing demand. Gas is a lower-carbon alternative to coal in power generation and industry, and to oil in transport. Gas can balance renewable energy to provide stability for national grids.

[A] Source: LNG Canada website lngcanada.ca

1. Gaslog Glasgow arriving at the LNG Canada facility for first cargo.



Upstream

The Upstream segment includes exploration and extraction of crude oil, natural gas and natural gas liquids. It also markets and transports oil and gas, and operates the infrastructure necessary to deliver them to the market. Shell has activities in deep water and conventional oil and gas.

At Capital Markets Day 2025, we said we would grow top-line production across our combined Upstream and Integrated Gas business by 1% (CAGR) per year to 2030, sustaining our 1.4 million barrels per day of liquids production to 2030. We will focus on basins where we have a competitive advantage and we will prioritise cost- and carbon-competitive molecules.

In 2025, we delivered strong operational performance, with high controllable availability, and increased contributions from higher-margin volumes, especially in the Gulf of America and Brazil. We also made significant progress on new production, already delivering 25% of the more than 1 million barrels of oil equivalent per day we promised by 2030.

We executed value-driven decisions to strengthen our business. We completed the divestment of The Shell Petroleum Development Company (SPDC) in Nigeria and the set-up of the new Adura Energy Limited joint venture in the UK. We further strengthened our deep-water leadership by increasing our interests in the Gulf of America, Brazil and Nigeria.

These actions contributed to sustained liquids production at about 1.4 million barrels per day, supported our growth target and generated robust cash flow despite the lower price environment. By leveraging our advantaged deep-water and conventional assets, we prioritised cost- and carbon-competitive molecules – delivering value and working towards lowering our emissions.

For the business conditions relevant to Upstream, see "Market overview" on pages 25-27.

[A] On a compound annual growth rate (CAGR) basis.

9.4

Income/(loss) for the period (\$ billion)
(2024: 7.8)

7.4

Adjusted Earnings (\$ billion)
(2024: 8.4)

19.6

Cash flow from operating activities (\$ billion)
(2024: 21.2)

1,828

Production (thousand boe/d)
(2024: 1,831)



“Upstream delivered strong operational results, with high controllable availability driving sustained high production.”

Peter Costello
President, Upstream

Financial delivery

2025 earnings [A]

Income/(loss) for the period was driven by the same factors as Adjusted Earnings and includes identified items.

Adjusted Earnings decreased by \$953 million compared with 2024. This reflected lower realised liquids prices (decrease of \$2,924 million) and the comparative unfavourable impact of gas storage effects (decrease of \$662 million). These net unfavourable movements were partly offset by lower well write-offs (decrease of \$915 million) and higher sales volumes (increase of \$901 million).

Identified items in 2025 included gains on the disposal of assets of \$2,806 million, mainly related to the incorporation of the Adura Energy limited joint venture in the UK, partly offset by a charge of \$536 million related to the UK Energy Profits Levy and impairment charges of \$162 million. These gains and charges compare with 2024, which included a loss of \$325 million related to the impact of the weakening Brazilian real on a deferred tax position, net impairment charges and reversals of \$323 million, and charges of \$214 million related to redundancy and restructuring. This was partly offset by gains of \$638 million related to the impact of inflationary adjustments in Argentina on a deferred tax position.

Adjusted EBITDA was driven by the same factors as Adjusted Earnings.

Prior year earnings [A]

Income/(loss) for the period was driven by the same factors as Adjusted Earnings and includes identified items.

Adjusted Earnings decreased by \$1,411 million compared with 2023. This reflected unfavourable tax movements (\$1,289 million), lower realised prices (decrease of \$949 million) and higher well write-offs (increase of \$541 million), partly offset by the comparatively favourable impact of \$962 million mainly relating to gas storage effects.

Identified items in 2024 included a loss of \$325 million related to the impact of the weakening Brazilian real on a deferred tax position, net impairment charges and reversals of \$323 million and charges of \$214 million related to redundancy and restructuring. This was partly offset by gains of \$638 million related to the impact of inflationary adjustments in Argentina on a deferred tax position. These charges and gains compare with 2023, which included net impairment charges and reversals of \$642 million, and net charges of \$295 million related to the impact of the weakening Argentine peso and strengthening Brazilian real on a deferred tax position.

Adjusted EBITDA was driven by the same factors as Adjusted Earnings.

Cash flow from operating activities

Cash flow from operating activities for 2025 was primarily driven by Adjusted EBITDA and dividends (net of profits) from joint ventures and associates of \$1,448 million. These inflows were partly offset by tax payments of \$7,415 million and movements in decommissioning and other provisions of \$1,087 million.

Cash capital expenditure

Cash capital expenditure in 2025 was higher compared with 2024. The increase was mainly a result of increased working interests in Brazil and the Gulf of America (GoA), as well as new projects, mainly in Brazil. This was partly offset by lower spend on projects mainly in Malaysia. Cash capital expenditure* is expected to be around \$7 billion in 2026.

Key metrics [B]

	\$ million, except where indicated		
	2025	2024	2023
Income/(loss) for the period	9,443	7,772	8,540
Identified items [B]	2,001	(623)	(1,266)
Adjusted Earnings* [B] [C]	7,442	8,395	9,806
Adjusted EBITDA* [C] [D]	26,696	31,264	30,622
Cash flow from operating activities	19,573	21,244	21,450
Cash capital expenditure*	9,316	7,890	8,343
Liquids production available for sale (thousand b/d)	1,365	1,320	1,325
Natural gas production available for sale (million scf/d)	2,684	2,964	2,754
Total production available for sale (thousand boe/d)	1,828	1,831	1,800

[B] See Note 7 to the "Consolidated Financial Statements" on pages 259-267.

[C] Adjusted Earnings and Adjusted EBITDA are presented on a current cost of supplies basis.

[D] Adjusted EBITDA is without taxation, exploration well write-offs and DD&A expenses.

Operational performance

Production available for sale

In 2025, liquids production increased by 3% and natural gas production decreased by 9%, compared with 2024.

Total production, compared with 2024, was flat, with reductions due to the divestment of The Shell Petroleum Development Company of Nigeria Limited (SPDC) and field decline offset by new liquids and gas production.

Strategic progress

Portfolio and business developments

Significant portfolio and business developments:

- In January 2025, we started production at the Shell-operated Whale floating production facility in the GoA. Shell has a 60% interest in the Whale development, and Chevron U.S.A. Inc. has a 40% interest.
- In February 2025, we restarted production at the Penguins field in the UK North Sea with a modernised Shell-operated FPSO facility (Shell interest 50%) NEO Energy holds the other 50%.
- In February 2025, we signed an agreement to acquire a 15.96% working interest from ConocoPhillips Company (COP) in the Shell-operated Ursa platform in the GoA. We completed this agreement in May 2025 and our working interest in the Ursa platform increased from 45.39% to 61.35%.
- In March 2025, we completed the sale of The Shell Petroleum Development Company of Nigeria Limited (SPDC) to Renaissance.
- In March 2025, we announced a final investment decision (FID) for Gato do Mato, a Shell-operated deep-water project in the pre-salt area of the Santos Basin, offshore Brazil. Pré-Sal Petróleo S.A. (PPSA) is the manager of the production-sharing contract (PSC). At FID, Shell held a 50% interest, Ecopetrol held 30%, and TotalEnergies had 20%. In January 2026, we increased our 50% interest in Gato do Mato (now Orca) to 70% after completing a swap agreement with TotalEnergies. In February 2026, we agreed to sell a 20% interest to Kuwait Petroleum Exploration Company (KUPPEC). The transaction is subject to regulatory approvals. Once completed, we will have a 50% interest and will remain operator, with Ecopetrol holding 30% and KUPPEC holding 20%.

[A] All earnings amounts are shown post-tax unless otherwise stated.

* Non-GAAP measure. See page 430.

- In May 2025, the start of production was announced at the FPSO Alexandre de Gusmão in the Mero field (Shell interest 19.3%) in the Santos Basin offshore Brazil. The unitised Mero field is operated by Petrobras (38.6%), in partnership with Shell, TotalEnergies (19.3%), CNPC (9.65%), China National Offshore Oil Corporation (CNOOC) (9.65%) and Pré-Sal Petróleo S.A. (PPSA) (3.5%) representing the government in the non-contracted area.
- In May 2025, we signed an agreement to acquire an additional interest of up to 12.5% in the OML 118 production-sharing contract (OML 118 PSC) in Nigeria from TotalEnergies EP Nigeria Limited. In November 2025, we completed this transaction and increased our interest in the OML 118 PSC from 55% to 65%.
- In October 2025, we announced, together with Sunlink Energies and Resources Limited, an FID on the HI gas project offshore Nigeria (Shell interest 40%).
- In December 2025, we and Equinor ASA completed a deal to combine our UK offshore oil and gas operations to form a new company Adura, which is a 50:50 joint venture.
- In December 2025, following an auction, we secured additional equity in Brazil's pre-salt oil projects. With this acquisition we will increase our participating interest in the Atapu unit from 16.663% to 16.917% and the Mero unit from 19.3% to 20%. Both projects are located in the offshore Santos Basin.
- In December 2025, we announced an FID on a waterflood project at the Kaikias field (Shell 100% interest) in the GoA.

Business and property

Our subsidiaries, joint ventures and associates are involved in all aspects of upstream activities. These activities include land tenure and the exploration, development and production of crude oil, natural gas and natural gas liquids. They also include the marketing and transportation of oil and gas, as well as the operation of the infrastructure necessary to deliver them to market. The contractual frameworks most relevant to our activities are set out on page 42.

Europe

Germany

Shell is a 50% shareholder in BEB Erdgas und Erdöl GmbH & Co. KG (BEB), which owns interests in various concessions, mainly in Lower Saxony. ExxonMobil Production Deutschland GmbH has a service contract with BEB, under which it provides operating services to BEB for most of the concessions.

Italy

Shell has a 39% interest in the Val d'Agri producing concession, operated by Eni S.p.A., and a 25% interest in the Tempa Rossa producing concession, operated by TotalEnergies EP Italia S.p.A.

Netherlands

Shell and ExxonMobil are 50:50 shareholders in Nederlandse Aardolie Maatschappij B.V. (NAM). NAM holds a 60% interest in the onshore low-calorific Groningen gas field (the remaining 40% interest is held by EBN, a Dutch government entity). NAM also holds the Schoonebeek oil field, 14 smaller hydrocarbon production licences and two underground gas storage facilities.

Historical production from the Groningen field induces earthquakes, which have led to damage claims, security concerns, and a strengthening operation to make buildings earthquake resistant.

In June 2018, NAM's shareholders and the Dutch government signed a Heads of Agreement (HoA) to, inter alia, reduce, and eventually cease, production from the Groningen field. Under the terms of the HoA, it was agreed that the Dutch government would pass on to NAM costs insofar as the costs corresponded to NAM's liability. Further agreements were signed to implement the HoA.

NAM is working with the Dutch government to fulfil its financial obligations for earthquake costs. These include compensating for damage caused by the earthquakes and paying to strengthen houses where this is required for safety. In 2022, NAM started arbitrations with the Dutch government to have its financial liability determined for the costs the Dutch government has charged to NAM in relation to the strengthening operation and the handling of claims for physical damage to property. The outcomes of these arbitrations are expected in 2026.

On the instructions of the Dutch government, production at the Groningen field ceased on October 1, 2023, and a law was passed to shut down the field permanently from April 19, 2024. On May 1, 2025, the sale of NAM Offshore B.V., the entity holding OneGas East, NAM's offshore asset in the Dutch North Sea, to Tenaz Energy was completed.

See Note 32 NAM (Groningen gas field) litigation in the "Consolidated Financial Statements" on page 303.

Norway

Shell holds participating interests in 11 production licences on the Norwegian continental shelf and is the operator of three of these. In 2025, Shell was awarded one new licence and relinquished five. Shell has participating interests in two producing gas fields in Norway: Shell-operated Ormen Lange (Shell interest 17.8%) and Equinor-operated Troll (Shell interest 8.19%). At Ormen Lange, the Phase 3 sub-sea compression project was completed and delivered first gas in June 2025. It is expected to increase recovery from 75% to 85% without increasing offshore emissions, using hydropower as its energy source.

Shell also holds a 10% participating interest in the Irpa gas discovery, operated by Equinor, which is under development. We operate two licences that are being decommissioned: Knarr and Gaupe.

In addition, Shell is the technical service provider for the Nyhamna gas facility, operated by Gassco, which processes and exports gas from several Norwegian fields.

UK

In July 2024, Shell signed an agreement with RockRose Energy Limited, a subsidiary of Viaro Energy, to divest its equity stake in 11 gas fields and one exploration prospect in the UK Southern North Sea and the onshore gas processing terminal in Bacton, England. However, in January 2026, Shell, ExxonMobil and Viaro Energy mutually agreed not to proceed with the transaction given that the completion conditions were not met. Shell and ExxonMobil will continue to own the assets, with Shell as operator.

Production from the Shell Penguins Field was restarted in February 2025 from a new, modernised FPSO facility (Shell interest prior to completion of the Adura transaction 50%).

The Victory Field (Shell interest prior to completion of the Adura transaction 100%), a subsea tieback to the Total-operated Greater Laggan Area facilities, produced first gas in September 2025, well ahead of the July 2026 planned start-up, enabled by strong drilling and offshore execution.

Significant progress has also been made on the Jackdaw project (Shell interest prior to completion of the Adura transaction 100%) in the North Sea and it is expected, subject to regulatory approval, to become operational in the fourth quarter of 2026. Following the Court of Session (Outer House) ruling in Scotland that work on the project could continue while new consents are being sought, work has proceeded and the topsides were safely towed out from Norway and installed on the Jackdaw jacket in October 2025. In September 2025, Shell submitted its Scope 3 assessment for the Jackdaw Field as part of the process to re-establish production consent for the project.

On November 28, 2025, the English High Court dismissed Oceana UK's judicial review challenge to the award of tranche three of the 33rd licensing round awards (including two licences awarded to Shell in the Mid-North Sea High area). Shell's 33rd round licences were transferred to Adura on December 1, 2025.

In July 2023, the UK government announced that the Acorn carbon capture, utilisation and storage project (Shell interest 30%) had been selected as one of two clusters to enter Track 2 of the UK's cluster sequencing process for carbon capture and storage (CCS). In June 2025, as part of the comprehensive Spending Review process, the UK government announced development funding to advance the Acorn carbon capture, utilisation and storage project towards an FID. The project is in discussions with the UK government to unlock this funding. In the meantime, short-term funding has been provided by the Scottish government.

The Offshore Petroleum Regulator for Environment and Decommissioning (OPRED) continues to assess the Brent field decommissioning programme for the Brent gravity-based substructures and has asked its Science and Technology Advisory Council (STAC) to conduct a short, focused review of the scientific and engineering evidence that underpins the Brent decommissioning programme recommendations. The next steps on the Brent decommissioning programme will be subject to the outcome of the STAC review.

Decommissioning of the Heather Alpha platform continued in 2025. The Heather Alpha platform topsides were safely removed and taken onshore for recycling in August 2025. Continued activity on the subsea well plug and abandonment campaign continued into 2025, specifically on Curlew, Pierce and Kingfisher, noting that Shell's interest in Pierce has transferred to Adura.

On December 1, 2025, Shell and Equinor ASA completed the combination of their UK offshore oil and gas assets and expertise to form an incorporated joint venture, Adura Energy Limited. Adura (Shell interest 50% and Equinor interest 50%) is based in Aberdeen, Scotland. The joint venture includes Equinor's former equity interests in Mariner, Rosebank and Buzzard; and Shell's former equity interests in Shearwater, Jackdaw, Penguins, Gannet, Nelson, Pierce, Victory, Clair and Schiehallion. A range of exploration licences are also part of the transaction. Excluded from the transaction are: Shell's interests in the Howe field; the SEGAL gas transportation system; those fields and facilities that have already ceased production; its equity stake in 11 gas fields and one exploration prospect in the UK Southern North Sea; and the onshore gas processing terminal in Bacton, England. In addition to these retained interests, decommissioning activities in all fields in the UK Continental Shelf are continuing, most of which are pursuant to the relevant Decommissioning Security Agreements.

Rest of Europe

Shell also has interests in Albania in Block 2/3. Shell issued a notice of non-commerciality of the Block 2/3 Discovery Area in 2025 to the Government of Albania.

Asia (including the Middle East)

Brunei

Shell and the Brunei government are 50:50 shareholders in Brunei Shell Petroleum Company Sendirian Berhad (BSP). BSP has long-term onshore and offshore oil and gas concession rights and sells most of its gas production to Brunei LNG Sendirian Berhad, with the remainder sold in the domestic market.

In addition to our interest in BSP, we have a non-operated 35% interest in the offshore Block B concession, which is operated by Hibiscus Petroleum. The gas and condensate are produced from the Maharajalela Jamalulalam field.

We operate the deep-water Block CA1 (Shell interest 86.95%) in which the Jagus East field is located and which forms part of the unitised GKGJE field under a PSC. As referred to in the Malaysia section, the unitised GKGJE field is operated by Shell Malaysia.

In December 2025, we relinquished our 20% non-operated interest in the deep-water block CA2.

See "Integrated Gas" on pages 28-34.

Iraq

Shell has a 44% interest in the Basrah Gas Company, which gathers, treats and processes associated gas that was previously flared from the Rumaila, West Qurna 1 and Zubair fields. Processed gas and associated products, such as condensate and LPG, are sold to the domestic and international markets.

Kazakhstan

Shell is the joint operator with ENI S.p.A. of the onshore Karachaganak oil and condensate field (Shell interest 29.3%) in north-west Kazakhstan which covers more than 280 square kilometres. One of the shareholders in Karachaganak is Lukoil (13.5% interest). We continue to manage our interest in compliance with international sanctions on Russia.

We also have a 16.8% interest in the North Caspian Sea PSA, which includes the Kashagan field in the Kazakh sector of the Caspian Sea. The North Caspian Operating Company is the operator. This shallow-water field covers around 3,400 square kilometres.

Shell has a 7.4% interest in the Caspian Pipeline Consortium (CPC), which owns and operates an oil pipeline running from the Caspian Sea to the Black Sea across parts of Kazakhstan and Russia. We hold our interest in the CPC via three legal entities. Two of these are wholly owned by Shell and the other is a joint venture with Rosneft, Rosneft-Shell Caspian Ventures Ltd (Cyprus) (RSCV) (Shell interest 49%), which was formed in 1996 to own and manage pipeline capacity rights. We continue to manage our interest in CPC held through RSCV in full compliance with applicable laws, including sanctions.

We have several matters in dispute involving non-operated ventures and the Republic of Kazakhstan, including court proceedings in respect of a sulphur permitting outcome and two arbitrations under the applicable production-sharing agreements. While we and the non-operated ventures have consistently upheld our commitment to legal compliance, adherence to all applicable laws, regulations, and production-sharing agreements, and we are actively defending our position in these proceedings, there remains a high degree of uncertainty regarding the outcomes, as well as the potential effects on future operations, earnings, cash flows and Shell's financial condition.

See Note 32 to the "Consolidated Financial Statements" on pages 302-304.

Kuwait

Shell Kuwait Exploration and Production B.V. (Shell interest 100%) holds three enhanced technical service agreements (ETSA) with Kuwait Oil Company. The ETSA Jurassic Gas, the ETSA Heavy Oil and ETSA Conventional Oil all run to 2029.

Malaysia

Shell explores for and produces oil and gas off the coast of Sabah and Sarawak under 20 PSCs, in which our interests range from 20% to 92.5%.

Offshore Sabah

We operate two producing oil fields: the Malikai deep-water field (Shell interest 35%) in the Block G PSC, and the unitised Gumusut-Kakap Geronggong-Jagus East (GKGJE) field in the Block J PSC which straddles the Malaysia–Brunei border (Shell interest 37.89%).

We hold a 50% operated participating interest in the exploration phase Block 2W, Block X, Block ND6 and Block ND7 PSCs. Our exploration activities in Block ND6 and Block ND7 PSCs were suspended in 2005 because of Malaysia's border disputes with Indonesia.

Our non-operated portfolio includes two producing fields: the unitised Siakap North-Petai deep-water field in Block G PSC (Shell interest 21%) and the Kebabangan Cluster PSC (Shell interest 30%), along with the Ubah Cluster PSC (Shell interest 35%), currently in the pre-development stage. We also hold interests in exploration phase Block SB 2K, Block N and Block 2V PSCs, which range from 25.1% to 40%.

Offshore Sarawak

We are the operator of four PSCs producing gas and oil, holding interests ranging from 30% to 75% under the MLNG, SK308, SK408 and SK318 PSCs. Nearly all the gas produced offshore Sarawak is supplied to Malaysia LNG (MLNG) and to the Shell MDS gas-to-liquids plant in Bintulu. We also continue to explore in the MLNG PSC.

The SK318 PSC contains the Timi field (Shell interest 75%), the unitised Rosmari field (Shell interest 68%) and the unitised Marjoram field (Shell interest 72%). Rosmari–Marjoram is a natural gas project currently under development, situated around 220 kilometres off the coast of Bintulu, comprising a remotely operated offshore platform and onshore gas plant. The production facilities for these fields will mainly be powered by renewable energy from solar power offshore and hydroelectric power onshore.

We hold participating interests ranging from 45% to 92.5% in the exploration Block SK437, Blocks SK439/440, Block 3B and Block 5E PSCs.

In our non-operated portfolio, we hold a 20% interest in the Pegaga field under the SK320 PSC and a 30% interest in the Jerun, Larak and Bakong fields which are part of the SK408 PSC.

See "Integrated Gas" on pages 28-34.

Oman

Shell has a 34% interest in Petroleum Development Oman (PDO), which operates the Block 6 oil concession. Shell is entitled to 34% of oil produced from Block 6 through its interest in Private Oil Holdings Oman Ltd. We have a 50% interest in Block 42 under an exploration and production-sharing agreement (EPSA) where Shell is the operator. We also operate in Block 55 under an EPSA (Shell interest 100%). We are in the process of relinquishing our interests in Block 42 and Block 55 to the government.

See "Integrated Gas" on pages 28-34.

Syria

Shell holds a 65% interest in Syria Shell Petroleum Development B.V. (SSPD), a joint venture between Shell and the China National Petroleum Corporation. SSPD holds a 31.25% interest in Al Furat Petroleum Company, a Syrian joint stock company whose role was to perform petroleum operations. Shell also holds a 70% interest in two exploration licences via Shell South Syria Exploration B.V. In December 2011, in compliance with international sanctions on Syria, including European Council Decision 2011/782/CFSP, Shell suspended all exploration and production activities in Syria and its participation in and/or support for activities related to Al Furat Petroleum Company. In the first half of 2025, most US sanctions in relation to Syria were revoked but all activities remain suspended. Syria is still classified by the USA as a State Sponsor of Terrorism (SST), there are still significant Syria-related designations, and some export controls remain. SSPD continued to fulfil minimum contractual obligations towards the Syrian finance and labour ministries, in compliance with applicable trade control laws. [A]

[A] In 2025, as part of the minimum contractual obligations, payments for taxes related to salary and social security amounted to \$282. In addition, in 2025, in compliance with applicable sanctions on Syria, we reimbursed three employees for visas and for renewal of passports of family members paid to the Syrian Embassy in Kuwait, totalling \$1,049.44.

Rest of Middle East and Asia

Shell has certain interests in the United Arab Emirates including a 15% shareholding in the Abu Dhabi Gas Industries Limited ("ADNOC Gas Processing") operating joint venture, which is a key supplier of natural gas in the country.

Africa

Nigeria

In 2025, Shell held a number of interests in onshore and offshore oil exploration and production assets in Nigeria.

Onshore

In March 2025, Shell completed the sale of The Shell Petroleum Development Company of Nigeria Limited (SPDC) to Renaissance. As part of the transaction and ongoing business arrangements, Shell provided loan facilities for amounts of up to \$2.5 billion. More recently, in December 2025 and January 2026, Shell's share of these loan facilities has been reduced by \$1 billion through a loan syndication. Shell will continue to support Renaissance in the development of its gas reserves and performance of the export feedgas business.

Offshore

Our main offshore activities are carried out by our wholly owned subsidiary Shell Nigeria Exploration and Production Company Limited (SNEPCo). SNEPCo has interests in three deep-water blocks that are under PSC terms: the producing assets Bonga (OML 118) and Erha (OML 133), and the non-producing asset Bolia Chota (OML 135). SNEPCo operates OML 118 (Shell interest 65%), including the Bonga field FPSO vessel. SNEPCo also operates OML 135 (Shell interest 55%), encompassing the Bolia and Doro fields. SNEPCo has a 43.8% non-operated interest in OML 133 (including the Erha FPSO). In addition, SNEPCo holds a 40% interest in a non-producing shallow-water lease (OML 144) that is held in a joint venture with Sunlink Energies.

In May 2025, we announced the acquisition of an additional interest in the OML 118 PSC, subject to conditions. We completed this agreement in November 2025 and increased our interest in the OML 118 PSC from 55% to 65%.

In October 2025, we announced an FID on the HI gas project under OML 144, following the conclusion of a gas supply agreement with Nigeria LNG Ltd (NLNG). Under this agreement, gas produced from the HI field will be supplied to NLNG.

During 2025, SNEPCo held a 50% interest in OPL 245. On March 4, 2026, this licence was converted under Nigeria's Petroleum Industry Act (2021) into two development leases (PML 102 and PML 103) and

two exploration licenses (PPL 2011 and PPL 2012), held by SNEPCo (35%), Nigeria Agip Exploration (35%) and Nigerian National Petroleum Company Limited (NNPCL) (30%). In addition, SNEPCo was awarded a 50% interest in a PSC with NNPCL in respect of NNPCL's 30% interest in these licences and leases.

See Note 32 to the "Consolidated Financial Statements" on pages 302-304 for more information about OPL 245.

Business update

Security issues, sabotage and crude oil theft in the Niger Delta have posed significant challenges to our onshore operations. In March 2025, we completed the sale of SPDC, which has reduced our exposure to risks associated with onshore operations.

Notwithstanding the above, in our remaining business activities in Nigeria, we continue to face various risks and adverse conditions that could have a significant adverse effect on our operational performance, earnings, cash flows and financial condition.

See "Environment" on pages 120-122.

There are limitations to the extent to which we can mitigate these risks.

We monitor the security situation and liaise with host communities, and governmental and non-governmental organisations to help promote peaceful and safe operations for our people and local communities. We test the economic and operational resilience of our Nigerian projects against a range of assumptions and scenarios. When we participate in joint ventures in Nigeria, we require that they operate in accordance with good industry practice. We seek to proportionally share risks and funding commitments with joint-venture partners.

Rest of Africa

Shell also has interests in Algeria, Namibia, São Tomé and Príncipe, South Africa and Tunisia.

In 2021, Shell announced plans to hand back upstream assets associated with the Miskar and Hasdrubal concessions to the government of Tunisia. In June 2022, Shell handed back the Miskar concession upon its expiry. Shell is in the process of terminating its activities in Tunisia, including relinquishing the Hasdrubal concession.

North America

USA

The majority of our oil and gas interests in the USA comprise leases for federal offshore blocks in the deep waters of the Gulf of America. Such leases usually have a fixed primary term and, once production is established, remain in effect through continued production, subject to compliance with the relevant terms and provisions (including applicable laws and regulations).

Gulf of America

Shell's major production area in the USA is the Gulf of America (GoA). We have a total of 285 active federal offshore leases where Shell is the operator, and 29 active federal offshore leases where Shell has a non-operated interest.

We are the operator of 10 production hubs: Mars (Shell interests 33.7% to 100%), Olympus (Shell interests 71.5% to 100%), Auger (Shell interests 27.5% to 100%), Perdido (Shell interests 32.5% to 40%), Ursa (Shell interests 50% to 100%), Enchilada/Salsa (Shell interests 37.5% to 75%), Appomattox (Shell interests 79% to 100%), Vito (Shell interest 63.1%), Stones (Shell interest 100%) and Whale

(Shell interest 58.5%). We also have an interest in the West Delta 143 offshore processing facilities (Shell interest 71.5%).

We continue to produce from the Coulomb field (Shell interest 100%), which ties into the Na Kika platform (Shell interest 50%) and which is co-owned and operated by BP Exploration and Production Inc.

We continued exploration, development and decommissioning activities in the GoA in 2025.

In January 2025, we began production at the Shell-operated Whale stand-alone host (Shell interest 58.5%). Whale is expected to produce up to 117,000 boe/d at peak rates in 2026.

In April 2025, we began production at Dover (Shell interest 100%), the second subsea tieback to the Shell-operated Appomattox production hub (Shell interest 79%). Dover is expected to produce up to 14,000 boe/d at peak rates in 2027.

In May 2025, we continued to build our GoA portfolio through inorganic growth, acquiring an additional 15.96% working interest in the Ursa platform/field (Shell interest now 61.35%).

In December 2025, an FID was taken on a "waterflood" project at the Kaikias field (Ursa platform) where water will be injected to displace additional oil. This process is due to begin in 2028 and is expected to extend the production life of the Ursa facility by several years.

Rest of North America

Shell also has deep-water licences and one shallow-water licence in Mexico, and we are in the process of relinquishing them to the government of Mexico.

South America

Argentina

Shell has interests in the onshore Vaca Muerta Basin in the Neuquén Province. We are the operator of the following areas: Cruz de Lorena, Sierras Blancas, Coiron Amargo Sur Oeste (Shell interest 90% in each) and Bajada de Añelo (Shell interest 50%). We have non-operated interests in the areas: Rincon La Ceniza and La Escalonada (Shell interest 45% in each), both operated by Vaca Muerta Investments SAU, and in Bandurria Sur (Shell interest 30%), operated by YPF S.A. Shell has a participating interest in the oil pipeline connecting Sierras Blancas and the regional distribution network and is the administrator in the joint property agreement that regulates its operation (Shell interest 60%). Shell also has a participating interest in the oil pipeline in the northern area of the basin, which connects to the Pacific Evacuation Route (Shell interest 13.3%), operated by YPF S.A., and a participating interest in VMOS S.A. whose main purpose is the construction of a 437 km pipeline to export unconventional crude oil production from Vaca Muerta to the Atlantic coast (Shell interest 8.2%).

In the north-western Argentina basin, we have a non-operated interest in the onshore Acambuco area (Shell interest 22.5%), operated by Pan American Energy.

We are also the operator of two frontier exploration blocks offshore Argentina, CAN107 and CAN109 (Shell interest 60% in each). In 2025, we relinquished a non-operated interest in an adjacent block, CAN100 (Shell interest 30%), operated by Equinor.

1.



Delivering in the Gulf of America

In the Gulf of America (GoA), Shell is a leading producer and operates 10 production hubs – making it a heartland for our deep-water operations. With decades of experience, we are leveraging our significant geological and technical expertise to deliver energy profitably and at lower costs, while reducing emissions.

Operational excellence

In 2023, our operations began a transformation to help deliver Shell's strategy to deliver more value with less emissions. This transformation journey is built on a foundation of safety and with a focus on performance, discipline and simplification.

In 2022, our asset controllable availability in the GoA was 87% and rose to 91% in 2024. Our 2024 production was 343 kboe/d, supported by over 96% controllable reliability for the second consecutive year. We also completed major turnarounds at Auger and Enchilada Salsa ahead of schedule, minimising downtime and maximising output. In 2025, asset controllable availability remained high at 88% and our production in the year was 377 kboe/d with 94% controllable reliability. We completed turnarounds at our Vito, Ursa, and Mars assets.

This performance is the result of plans tailored to each asset's life cycle – whether late-life, mature or a newer, lower-cost host like Vito (Shell interest 63.1%) and Whale (Shell interest 58.5%), which exemplifies operational prowess. Starting production in January 2025, Whale was designed for nameplate output of 100,000 boe/d and reached this capacity within less than half the planned time. We now expect peak production to be 117,000 boe/d in 2026 [A].

Technology and innovation

We power our activities by advanced technologies and innovation, helping to reduce costs and accelerate timelines. By using existing infrastructure for tiebacks and infill drilling, we have optimised resource utilisation. For example, in April 2025, we began production at Dover (Shell interest 100%), the second subsea tieback to our operated Appomattox hub (Shell interest 79%). Dover is expected to produce up to 14,000 boe/d at peak rates.

Digitalisation plays a critical role. Remotely connected platforms enable real-time data collection and live-streamed equipment inspections, reducing offshore travel and cutting maintenance costs – most of Whale's operations are managed from New Orleans, which is about 600 kilometres away from the platform.

Enhanced recovery techniques, such as water flooding and gas lift, have also been employed to help improve efficiency. In December 2025, a final investment decision was taken on a waterflood project at the Kaikias field for the Ursa platform (Shell interest 61.35%). Here, water will be injected to displace additional oil. This is due to begin in 2028 and is expected to extend Ursa's production life cycle by several years.

Our people

Across Shell, people development is a priority. In the GoA, we have upskilled our teams through additional training, such as in AI and data literacy, and safety technology and robotics – enhancing their operational capability to help us drive performance.

Shell puts a focus on safety first, and in the GoA, as elsewhere, we are using cutting-edge tools – like robotics for high-risk inspections and managed pressure drilling systems – to help improve safety.

Our GoA business demonstrates how disciplined execution, operational excellence and technology-led innovation can deliver strong performance from a mature deep-water portfolio. Through improved reliability, efficient project delivery and the use of advanced digital and subsurface technologies, we are maximising value from our assets while reducing costs and emissions.

Our focus on safety, people capability and fit-for-purpose solutions across the asset life cycle underpins performance, even in challenging operating conditions. This competitiveness positions Shell to close the gap to potential and be best-in-basin, delivering resilient energy today while building long-term value.

1. Gulf of America deep-water platform, Mars, 2025.

[A] The estimated peak production is 100% total gross figure.

Brazil

Shell operates the Bijupirá and Salema fields (Shell interest 80% in each), which are being decommissioned; the producing fields in BC-10 block (Shell interest 50%) in the Campos Basin; and the Gato do Mato and adjacent Sul de Gato do Mato areas in the Santos Basin (Shell interest 70% [A]), which are subject to an ongoing unitisation process.

In March 2025, Shell announced an FID on Gato do Mato, a deep-water offshore project, which is scheduled to start operations in 2029. The project was renamed Orca after the Declaration of Commerciality.

We also hold interests as operator in 15 exploration blocks in the Santos Basin (Shell interests 70% to 100%), six exploration blocks in the Barreirinhas Basin (Shell interests 50% to 100%), three in the Campos Basin (Shell interests 40% to 100%) and one in the Potiguar Basin (Shell interest 100%).

Our non-operated portfolio consists of eight producing fields in the offshore Santos Basin and one producing area in the offshore Campos Basin:

- the Sapinhoá field (Shell interest 30%, operated by Petrobras and straddling the BM-S-9 and Entorno de Sapinhoá blocks already unitised and redetermined);
- the Lapa field (Shell interest 27%[B] in BM-S-9A block, operated by TotalEnergies);
- the Berbigão and Sururu fields (Shell interest 25% in BM-S-11A block, operated by Petrobras and subject to an ongoing unitisation process);
- the Atapu field (Shell interest 16.7% and straddling the BM-S-11A and Atapu PSC area already unitised);
- the Tupi field (Shell interest 22.65%, already unitised and redetermined, in BM-S-11 block and operated by Petrobras). In December 2025, the redetermination of Tupi became effective, resulting in a reduction of our participation interest in the unit from 23.02% to 22.65%;
- the Iracema field (Shell interest 25% in BM-S-11 block and operated by Petrobras);
- the Mero field in the Libra PSC area (Shell interest 19.3%, unitised and operated by Petrobras); and
- the Jubarte area (Shell interest 0.43%, operated by Petrobras) in the Campos Basin. In August 2025, the Jubarte unitisation was approved by the regulator. This comprises an extension into the Argonauta field in BC-10 block.

In addition to the producing assets, we hold interests in 33 non-operated exploration blocks: two in the Santos Basin (Shell interests 20% to 40%, operated by Petrobras); two in the Potiguar Basin (Shell interests 40%, both operated by Petrobras); and 29 blocks in the Pelotas Basin (Shell interests 30%, all operated by Petrobras).

In May 2025, production began at the Alexandre de Gusmão FPSO in the Mero field. This addition brings the total number of FPSOs in Mero to four, alongside an early production system, resulting in a combined installed production capacity of 770,000 b/d (100% total gross figure).

In December 2025, we secured additional equity in Brazil's pre-salt oil projects following an auction led by Pré-Sal Petroléo. Together with Petrobras, we deepened our stake in the Atapu and Mero units, acquiring 26.76% of Atapu Open Acreage (0.95% of the unit) and 20% of Mero Open Acreage (3.5% of the unit). With this acquisition, we will increase our participating interests in the units from 16.663% to 16.917% in Atapu and from 19.3% to 20% in Mero. The increased working interests are expected to take effect from 2027.

[A] In January 2026, Shell increased its interest in Gato do Mato from 50% to 70%, following the completion of a swap agreement with TotalEnergies. In February 2026, Shell agreed to sell a 20% interest to Kuwait Petroleum Exploration Company. Following completion, subject to regulatory approvals, Shell will maintain a 50% interest and will remain the operator.

[B] In January 2026, Shell reduced its interest in the Lapa field from 30% to 27%, following the completion of a swap agreement with TotalEnergies.

Rest of South America

Shell also has interests in Suriname and Uruguay. In Uruguay, Shell holds 100% interests in offshore blocks OFF-2 and OFF-7, and a non-operated 50% equity position in OFF-4.

Trading and supply

Shell markets and trades equity crude oil from its Upstream operations through our main trading offices in the UK, Singapore, the USA, The Bahamas and Canada. We are active in most crude oil markets and, with our global network of supply and distribution activities and shipping and maritime capabilities, we manage and optimise the supply of crude to Shell's refineries and the sale of crude to third-party customers.

Contractual frameworks of oil and gas activities

The conditions of the leases, licences and contracts under which oil and gas interests are held vary from country to country. In almost all cases outside North America, legal agreements are generally granted by, or entered into with, a government, state-owned company, government-run oil and gas company or agency. The exploration risk usually rests with the independent oil and gas company. In North America, these agreements may also be with private parties that own mineral rights. Of these agreements, the following are most relevant to our interests:

- Licences (or concessions), which entitle the holder to explore for hydrocarbons and exploit any commercial discoveries. Under a licence, the holder bears the risk of exploration, development and production activities, and is responsible for financing these activities. In principle, the licence holder is entitled to the totality of production less any royalties in kind. The government, state-owned company or government-run oil and gas company may sometimes enter into a joint arrangement as a participant, sharing the rights and obligations of the licence but usually without sharing the exploration risk. In a few cases, the state-owned company, government-run oil and gas company or agency has an option to purchase a certain share of production.
- Lease agreements, which are typically used in North America, are usually governed by terms similar to licences. Participants may include governments or private entities. Royalties are paid either in cash or in kind.
- Production-sharing contracts (PSCs) are entered into with a government, state-owned company or government-run oil and gas company. PSCs generally oblige the independent oil and gas company, as contractor, to provide all the financing and bear the risk of exploration, development and production activities in exchange for a share of the production. Usually, this share consists of a fixed or variable part that is reserved for the recovery of the contractor's cost (cost oil). The remaining production is split with the government, state-owned company or government-run oil and gas company on a fixed or volume-revenue-dependent basis. In some cases, the government, state-owned company or government-run oil and gas company will participate in the rights and obligations of the contractor and will share in the costs of development and production. Such participation can be across the venture or on a field-by-field basis. Additionally, as the price of oil or gas increases above certain pre-determined levels, the independent oil and gas company's entitlement share of production normally decreases, and vice versa. Accordingly, its interest in a project may not be the same as its entitlement.



Gato do Mato, now "Orca", is testament to resilience and discipline

In March 2025, we reached the final investment decision (FID) on the Gato do Mato deep-water project in Brazil's Santos Basin, about 200 kilometres offshore Rio de Janeiro. This marked the culmination of a 15-year effort with a number of challenges faced. What we viewed as a good opportunity to invest in became even better and is testament to the resilience, innovation and initiative of the people involved.

Shell is the largest foreign producer in Brazil, and the country is a cornerstone of our upstream operations. The project is designed to deliver peak production of up to 120,000 b/d, reinforcing our leadership in deep-water development.

Rethinking our approach

The path to taking an FID was far from straightforward. Oil was first discovered in 2010, but initial leases lacked sufficient potential to justify development. Securing an adjacent block through a competitive bid delayed progress for years. When we relaunched the project in 2022 as "Gato do Mato 2.0", global market volatility, driven by the Russia–Ukraine conflict and pandemic-related supply chain disruptions, pushed costs sharply higher. These challenges demanded changes to keep the project viable.

Rather than abandon the opportunity, our team rethought its approach. Working closely with Modec, the contractor responsible for the floating production, storage and offloading (FPSO) unit, we applied lessons from projects like Vito and Whale in the Gulf of America to redesign the development.

This collaboration produced significant results: production capacity is expected to increase by 20%, compared to the previous design, projected overall costs are expected to fall by nearly 16% and the expected topside weight was reduced by 30% as a result of removing unnecessary equipment.

The project, now renamed Orca, incorporates a simplified FPSO design coupled with a streamlined subsea system and well layout strategy that enables optimised volume recovery while providing flexibility for future development. The field development choices made post-recycle reduced costs and accelerated recovery while cutting expected greenhouse gas emissions by 20% compared to the earlier project designs.

Innovation and cost discipline

These improvements reflect our ability to adapt under pressure, combining technical innovation with strict cost discipline to overcome market and operational challenges. The Orca design is not only efficient but also scalable, opening opportunities for future deep-water projects and smaller field developments globally.

In January 2026, we increased our interest in Orca from 50% to 70%, following the completion of a swap agreement with TotalEnergies. In February 2026, we agreed to sell a 20% interest to Kuwait Petroleum Exploration Company. Following completion, subject to regulatory approvals, we will maintain a 50% interest in Orca.

Orca now moves into execution. Shell Brasil operates the project with partners Ecopetrol (30%) and PPSA as the contract manager. The FPSO is set to be built in China and Japan and installed offshore Brazil in 2028. Orca is expected to begin operations in 2029. This achievement underscores how Shell's resilience and disciplined approach turned a complex, delayed project into a viable and forward-looking development.

1. First hull block being placed in the dry dock at Sumitomo Heavy Industries Marine & Engineering Yokosuka.

Oil and gas information

This section sets out information about Shell's oil and gas exploration and production activities, which include the extraction of oil, condensates, natural gas liquids, oil sands and natural gas from their natural reservoirs. These activities are undertaken within the Integrated Gas, Upstream and the Chemicals and Products (includes oil sands) segments. They do not represent the full extent of the activities of these segments, and exclude gas-to-liquids (GTL) processing, some liquefied natural gas (LNG) activities, trading and optimisation, and other non-extractive activities.

Proved developed and undeveloped reserves of Shell subsidiaries and Shell share of joint ventures and associates

	Crude oil and natural gas liquids (million barrels)	Synthetic crude oil (million barrels)	Natural gas (thousand million scf)	Total (million boe)
Shell subsidiaries				
At January 1, 2025	3,526	741	22,558	8,156
Increase/(decrease) in 2025:				
Revisions and reclassifications	242	—	1,515	504
Improved recovery	16	—	—	16
Extensions and discoveries	44	—	755	174
Purchases and sales of minerals in place [C]	(193)	(725)	(2,113)	(1,282)
Total before taking production into account	109	(725)	157	(588)
Production [A]	(518)	(16)	(2,590)	(981)
Total	(409)	(741)	(2,433)	(1,569)
At December 31, 2025	3,117	—	20,125	6,587
Shell share of joint ventures and associates				
At January 1, 2025	363	—	6,384	1,464
Increase/(decrease) in 2025:				
Revisions and reclassifications	37	—	251	80
Improved recovery	—	—	—	—
Extensions and discoveries	—	—	13	2
Purchases and sales of minerals in place [C]	56	—	131	79
Total before taking production into account	93	—	395	161
Production [B]	(27)	—	(363)	(89)
Total	66	—	32	72
At December 31, 2025	429	—	6,416	1,536
Totals				
At January 1, 2025	3,889	741	28,942	9,620
Increase/(decrease) before taking production into account	202	(725)	552	(427)
Production	(545)	(16)	(2,953)	(1,070)
Total increase/(decrease)	(343)	(741)	(2,401)	(1,497)
At December 31, 2025	3,546	—	26,541	8,123
Reserves attributable to non-controlling interest in Shell subsidiaries at December 31, 2025	—	—	—	—

[A] Includes 44 million boe consumed in operations (natural gas: 249 thousand million scf; synthetic crude oil: 1 million barrels).

[B] Includes 4 million boe consumed in operations (natural gas: 26 thousand million scf).

[C] Includes the divestment of The Shell Petroleum Development Company of Nigeria Limited (SPDC), and the swap of Shell's remaining mining interest and associated synthetic crude oil reserves in the Canadian oil sands for an additional 10% interest (20% in total) in the Scotford upgrader and Quest CCS facility. Also includes the volumes movement from subsidiaries to joint ventures and associates due to formation of the Adura joint venture.

Proved reserves

Before taking production into account, our proved reserves decreased by 427 million boe in 2025. This consisted of a decrease of 588 million boe from Shell subsidiaries and an increase of 161 million boe from the Shell share of joint ventures and associates. After taking production into account, our proved reserves decreased by 1,497 million boe in 2025 to 8,123 million boe at December 31, 2025.

Shell subsidiaries

Before taking production into account, Shell subsidiaries' proved reserves decreased by 588 million boe in 2025. This consisted of a decrease of 725 million barrels of synthetic crude oil, an increase of 109 million barrels of crude oil and natural gas liquids, and an increase of 28 million boe (157 thousand million scf) of natural gas. The 588 million boe decrease comprised a net decrease of 1,282 million boe related to purchases and sales of minerals in place, a net increase of 504 million boe from revisions and reclassifications, an increase of 174 million boe from extensions and discoveries, and an increase of 16 million boe from improved recovery.

After taking into account production of 981 million boe (of which 44 million boe were consumed in operations), Shell subsidiaries' proved reserves decreased by 1,569 million boe in 2025 to 6,587 million boe. In 2025, Shell subsidiaries' proved developed reserves (PD) decreased by 1,249 million boe to 5,097 million boe and proved undeveloped reserves (PUD) decreased by 320 million boe to 1,490 million boe.

Shell share of joint ventures and associates

Before taking production into account, the Shell share of joint ventures and associates' proved reserves increased by 161 million boe in 2025. This consisted of an increase of 93 million barrels of crude oil and natural gas liquids, and an increase of 68 million boe (395 thousand million scf) of natural gas. The 161 million boe increase comprised a net increase of 80 million boe from revisions and reclassifications, a net increase of 79 million boe related to purchases and sales in place and an increase of 2 million boe from extensions and discoveries.

After taking into account production of 89 million boe (of which 4 million boe were consumed in operations), the Shell share of joint ventures and associates' proved reserves increased by 72 million boe to 1,536 million boe at December 31, 2025.

The Shell share of joint ventures and associates' PD increased by 40 million boe to 557 million boe, and PUD increased by 32 million boe to 979 million boe.

See "Supplementary information - oil and gas (unaudited)" on pages 307-325 for more information about proved oil and gas reserves of Shell subsidiaries and the Shell share of the proved oil and gas reserves of joint ventures and associates.

Proved undeveloped reserves

In 2025, Shell subsidiaries' and the Shell share of joint ventures and associates' PUD decreased by 288 million boe to 2,469 million boe. There were decreases of 357 million boe as a result of maturation to PD (mainly 100 million boe in Whale (USA), 59 million boe in Mero (Brazil), 37 million boe in Ormen Lange (Norway), and 161 million boe spread across other fields); a net decrease of 169 million boe as a result of purchases and sales of minerals in place (mainly a decrease of 163 million boe due to divestment of SPDC in Nigeria, a decrease of 38 million boe due to movement of Shell-UK fields to the Adura joint venture which was partly offset by an increase of 19 million boe following the formation of the Adura joint venture, and an increase of 13 million boe spread across other fields); an increase of 62 million boe due to de-maturation of PD to PUD; an increase of 176 million boe due to extensions and discoveries (mainly 85 million boe in Geryon (Australia) and 91 million boe spread across other fields); an increase of 16 million boe due to improved recovery; and a net decrease of 16 million boe due to revisions and reclassifications.

In addition to the maturation of 357 million boe from PUD to PD, 68 million boe were matured to PD as through PUD as a result of project execution during the year.

PUD held for five years or more (PUD5+) on December 31, 2025, amounted to 40 million boe, a decrease of 98 million boe compared with the end of 2024. The decrease in PUD5+ during 2025 was driven mainly by the divestment of SPDC (Nigeria).

The fields with the largest PUD5+ on December 31, 2025 were Kashagan (Kazakhstan), Clair (UK), Tupi (Brazil) and Atapu (Brazil). These PUD5+ remain undeveloped because of third-party gas plant delays (Kazakhstan), rig constraints (UK) and constraints related to export pipeline commissioning and drilling constraints due to development phasing (Brazil).

During 2025, we spent \$9.6 billion on development activities related to PUD maturation.

Delivery commitments

We sell crude oil and natural gas from our producing operations under a variety of contractual obligations. Most contracts generally commit us to sell quantities based on production from specified properties, although some natural gas sales contracts specify delivery of fixed and determinable quantities, as discussed below.

In the past three years, we met our contractual delivery commitments, with the notable exception of Malaysia (in 2023). In the period 2026-2028, we are contractually committed to deliver to third parties, joint ventures and associates a total of some 4,395 billion scf of natural gas from our subsidiaries, joint ventures and associates. The sales contracts contain a mixture of fixed and variable pricing formulae that are generally referenced to the prevailing market price for crude oil, natural gas or other petroleum products at the time of delivery.

In the period 2026-2028, we expect to meet our delivery commitments with an estimated 70% coming from PD, 5% through the delivery of gas that becomes available to us from paying royalties in cash, and 25% from the development of PUD and other new projects and purchases.

Summary of proved oil and gas reserves of Shell subsidiaries and Shell share of joint ventures and associates (at December 31, 2025)

Based on average prices for 2025

	Crude oil and natural gas liquids (million barrels)	Natural gas (thousand million scf)	Synthetic crude oil (million barrels)	Total (million boe) [A]
Proved developed				
Europe	75	2,127	—	442
Asia	1,266	9,006	—	2,819
Oceania	35	4,290	—	775
Africa	93	113	—	113
North America	—	—	—	—
USA	330	370	—	393
Canada	1	250	—	44
South America	896	996	—	1,068
Total proved developed	2,696	17,152	—	5,654
Proved undeveloped				
Europe	10	171	—	40
Asia	412	5,129	—	1,296
Oceania	31	1,999	—	375
Africa	75	91	—	91
North America	—	—	—	—
USA	76	68	—	88
Canada	—	—	—	—
South America	246	1,931	—	579
Total proved undeveloped	850	9,389	—	2,469
Total proved developed and undeveloped				
Europe	85	2,298	—	482
Asia	1,678	14,135	—	4,115
Oceania	66	6,289	—	1,150
Africa	168	204	—	204
North America	—	—	—	—
USA	406	438	—	481
Canada	1	250	—	44
South America	1,142	2,927	—	1,647
Total	3,546	26,541	—	8,123
Reserves attributable to non-controlling interest in Shell subsidiaries	—	—	—	—

[A] Natural gas volumes are converted into oil equivalent using a factor of 5,800 scf per barrel.

Exploration

Shell continues to explore for and mature hydrocarbons across our Integrated Gas and Upstream businesses. Exploration may result in discoveries of oil and gas that we can develop, helping maintain energy security and contributing to our strategy.

We use our integrated exploration, development, and project, commercial and technical expertise to mature these opportunities and actively manage technical and non-technical risks. We benchmark our projects internally and externally to improve the competitiveness of our proposals and seek to actively manage the risks during implementation. We assess the maturation progress of our various opportunities and perform post-investment reviews to extract learnings for implementation in future opportunities and to strengthen delivery predictability.

In 2025, hydrocarbons were found in the UK, Oman and Gulf of America.

Key exploration portfolio developments

UK

We relinquished two operated licences (Shell interests 55.5% and 100%) and also one operated block (Shell interest 100%). Following the completion of the combination of Shell and Equinor's UK offshore oil and gas assets into the Adura joint venture on December 1, 2025, all Shell UK working interests in exploration licences will be reduced by 50%.

Gulf of America

We farmed into four non-operated licences in the Walker Ridge area (Shell interests 22.5%). We also acquired 14 operated leases (Shell interest 51% in each) as part of an interest transfer involving 19 leases already held and three acquired (Shell interest 51%, operator). Additionally, we acquired one operated lease (Shell interest 75%) and three non-operated (Shell interests 30.6%).

We relinquished 28 operated leases (Shell interests 35% to 100%) and 35 non-operated leases (Shell interests 25% to 50%).

Brazil

We acquired four blocks in the Santos Basin in the OPC5 Bid Round (Shell interest 100%, operator).

Other

In Bulgaria, we signed a Prospecting and Exploration Agreement with the Bulgarian government for an offshore licence in the Western Black Sea (Shell interest 100%).

In Norway, the government ratified one operated licence (Shell interest 30%). We also relinquished four non-operated licences (Shell interests 20% to 40%) and one operated licence (Shell interest 40%).

In São Tomé and Príncipe, we farmed out 55% of our interest in one operated block and our remaining interest is 30%.

In Argentina, we relinquished one non-operated licence (Shell interest 30%).

In Suriname, we farmed out 20% of our interest in one operated block and our remaining interest is 40%.

See "Supplementary information - oil and gas (unaudited)" on pages 307-325.

Location of oil and gas exploration and production activities

Location of oil and gas exploration and production activities [A] (at December 31, 2025)

	Exploration	Development and/or Production	Shell operator [B]
Europe			
Albania [C]	●		●
Bulgaria	●		●
Cyprus		●	
Germany		●	
Italy		●	
Netherlands		●	●
Norway	●	●	●
UK	●	●	●
Asia			
Brunei	●	●	●
China		●	●
Kazakhstan		●	
Malaysia	●	●	●
Oman	●	●	●
Qatar		●	●
Oceania			
Australia	●	●	●
Africa			
Egypt	●	●	●
Namibia	●		●
Nigeria	●	●	●
São Tomé and Príncipe	●		●
South Africa	●		●
Tanzania	●	●	●
North America			
Barbados	●		
Canada	●	●	●
Mexico	●		●
USA	●	●	●
South America			
Argentina	●	●	●
Bolivia		●	
Brazil	●	●	●
Suriname	●		●
Trinidad and Tobago	●	●	●
Uruguay	●		●
Venezuela [D]		●	●

[A] Includes joint ventures and associates. Where a joint venture or an associate has properties outside its base country, those properties are not shown in this table.

[B] In several countries where "Shell operator" is indicated, Shell is the operator of some but not all exploration and/or production ventures.

[C] Shell issued a notice of non-commerciality in 2025 to the government of Albania.

[D] Our previous Office of Foreign Assets Control (OFAC) licence was withdrawn in 2025 in line with US policy at the time, meaning that we have been unable to undertake any activities related to our Venezuela interest since then. In mid-February 2026, the USA issued several general licences that authorise various activities in Venezuela, including one that allows certain companies to engage in oil and gas operations in Venezuela and produce from its reserves. We are currently reviewing these general licences to understand how they impact our activities.

Oil and gas production available for sale**Crude oil and natural gas liquids [A]**

	2025		2024		2023	
	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates
Europe						
Italy	7,707	—	8,551	—	8,373	—
UK	24,583	1,477	22,910	—	23,458	—
Other [B]	3,082	439	2,730	526	2,493	524
Total Europe	35,372	1,916	34,191	526	34,324	524
Asia						
Brunei	1,274	17,547	1,148	15,987	1,271	14,395
Kazakhstan	39,783	—	37,744	—	38,765	—
Malaysia	11,680	—	11,763	—	12,630	—
Oman	89,228	—	86,235	—	82,849	—
Other [B]	24,741	7,287	24,068	7,392	25,240	7,443
Total Asia	166,706	24,834	160,958	23,379	160,755	21,838
Oceania						
Australia	10,740	—	12,775	—	10,370	—
Total Oceania	10,740	—	12,775	—	10,370	—
Africa						
Nigeria	24,424	—	39,758	—	37,137	—
Other [B]	972	—	978	—	1,084	—
Total Africa	25,396	—	40,736	—	38,221	—
North America						
USA	117,417	—	108,090	—	112,912	—
Canada	568	—	538	—	597	—
Total North America	117,985	—	108,628	—	113,509	—
South America						
Argentina	15,482	—	15,610	—	12,152	627
Brazil	145,788	—	133,355	—	136,825	—
Other [B]	946	—	1,240	—	1,425	—
Total South America	162,216	—	150,205	—	150,402	627
Total	518,415	26,750	507,493	23,905	507,581	22,989

[A] Reflects 100% of production of subsidiaries except in respect of production-sharing contracts (PSCs), where the figures shown represent the entitlement of the subsidiaries concerned under those contracts.

[B] Comprises countries where production was lower than 10,100 thousand barrels or where specific disclosures are prohibited.

Synthetic crude oil

	Thousand barrels		
	2025	2024	2023
	Shell subsidiaries	Shell subsidiaries	Shell subsidiaries
North America - Canada	15,182	18,548	19,102

Natural gas [A]

	2025		2024		Million standard cubic feet 2023	
	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates
Europe						
Netherlands	—	26,757	—	37,601	—	55,351
Norway	173,302	—	176,629	—	150,318	—
UK	74,893	4,948	61,098	—	70,585	—
Other [B]	35,382	—	36,570	—	38,774	—
Total Europe	283,577	31,705	274,297	37,601	259,677	55,351
Asia						
Brunei	12,571	145,497	15,276	144,410	13,531	136,684
China	30,127	—	39,592	—	48,170	—
Kazakhstan	73,822	—	75,668	—	75,521	—
Malaysia	197,532	—	219,485	—	173,638	—
Oman	87,883	—	83,520	—	55,675	—
Other [B]	361,487	117,726	354,653	118,375	369,125	118,252
Total Asia	763,422	263,223	788,194	262,785	735,660	254,936
Oceania						
Australia	690,675	41,955	736,482	39,281	700,248	29,773
Total Oceania	690,675	41,955	736,482	39,281	700,248	29,773
Africa						
Egypt	45,766	—	27,737	—	21,434	—
Nigeria	24,434	—	129,533	—	96,967	—
Other [B]	1,192	—	3,022	—	3,423	—
Total Africa	71,392	—	160,292	—	121,824	—
North America						
USA	117,267	—	100,971	—	104,079	—
Canada	158,925	—	152,576	—	137,660	—
Total North America	276,192	—	253,547	—	241,739	—
South America						
Bolivia	28,958	—	33,453	—	35,432	—
Brazil	72,099	—	66,534	—	71,162	—
Trinidad and Tobago	135,334	—	159,937	—	199,877	—
Other [B]	19,812	—	17,942	—	14,204	857
Total South America	256,203	—	277,866	—	320,675	857
Total	2,341,461	336,883	2,490,678	339,667	2,379,823	340,917

[A] Reflects 100% of production of subsidiaries except in respect of PSCs, where the figures shown represent the entitlement of the subsidiaries concerned under those contracts.

[B] Comprises countries where production was lower than 41,795 million scf or where specific disclosures are prohibited.

Average realised price by geographical area**Crude oil and natural gas liquids**

	2025		2024		\$ /barrel 2023	
	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates
Europe	64.83	65.29	70.82	76.61	77.19	79.10
Asia	66.70	69.10	76.13	79.77	76.57	82.24
Oceania	56.76	—	63.98	—	58.31	—
Africa	71.73	—	79.63	—	84.33	—
North America - USA	62.94	—	74.07	—	75.07	—
North America - Canada	31.56	—	38.52	—	46.45	—
South America	60.49	—	71.85	—	71.93	67.98
Total	63.83	69.04	74.04	79.70	75.12	81.75

Synthetic crude oil

	2025	2024	\$ /barrel 2023
	Shell subsidiaries	Shell subsidiaries	Shell subsidiaries
North America - Canada	58.66	68.35	69.26

Natural gas

	2025		2024		\$ /thousand scf 2023	
	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates
Europe	12.76	9.34	12.76	9.63	17.47	18.89
Asia	2.45	6.57	2.62	7.23	2.84	7.60
Oceania	9.33	5.65	10.47	6.40	11.05	6.23
Africa	9.27	—	3.02	—	3.25	—
North America - USA	4.20	—	3.50	—	3.74	—
North America - Canada	1.40	—	1.19	—	2.25	—
South America	3.75	—	4.13	—	5.10	3.69
Total	6.29	6.67	6.47	7.44	7.40	9.78

Average production cost by geographical area**Crude oil, natural gas liquids and natural gas [A]**

	2025		2024		\$ / boe 2023	
	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates
Europe	17.07	23.16	17.05	28.54	20.93	25.33
Asia	6.33	7.95	6.33	9.10	6.35	9.64
Oceania	8.23	14.52	7.85	19.49	9.01	21.23
Africa	11.78	—	11.95	—	11.12	—
North America - USA	8.78	—	10.11	—	9.62	—
North America - Canada	9.01	—	9.30	—	9.70	—
South America	8.47	—	7.51	—	7.36	9.03
Total	8.73	9.83	8.74	11.60	9.08	12.29

[A] Natural gas volumes are converted into oil equivalent using a factor of 5,800 scf per barrel.

Synthetic crude oil

	2025	2024	\$ / barrel 2023
	Shell subsidiaries	Shell subsidiaries	Shell subsidiaries
North America - Canada	19.76	17.00	19.47



Marketing

The Marketing segment comprises the Mobility, Lubricants, and Sectors and Decarbonisation businesses. The Mobility business operates Shell's retail network including electric vehicle charging services and the wholesale commercial fuels business, which provides fuels for transport and industry. The Lubricants business produces, markets and sells lubricants for road transport, and machinery used in manufacturing, mining, power generation, agriculture and construction. The Sectors and Decarbonisation business sells fuels, speciality products and services, including low-carbon energy solutions, to a broad range of commercial customers including the aviation, marine and agricultural sectors.

We are pursuing focused growth in our high-return Mobility and Lubricants businesses. The Marketing business delivered strong results in 2025, with a continuing focus on value over volume. Mobility and Lubricants delivered higher margins through increased sales of premium products whilst also reducing operating costs. Both Mobility and Lubricants achieved their best-ever results in 2025, though Sectors and Decarbonisation margins fell.

This strong performance was supported by the divestment or closure of lower-performing branded retail sites and the high-grading of our portfolio. In line with our strategic focus on disciplined capital allocation to help ensure competitive returns, we decided in September 2025 not to restart construction of the planned biofuels facility at the Shell Energy and Chemicals Park Rotterdam. Construction was paused in 2024.

For the business conditions relevant to Marketing, see "Market overview" on pages 25-27.

2.1

Income/(loss) for the period (\$ billion)
(2024: 1.7)

4.0

Adjusted Earnings (\$ billion)
(2024: 3.9)

6.3

Cash flow from operating activities (\$ billion)
(2024: 7.4)

2,753

Marketing sales volumes (thousand b/d)
(2024: 2,843)



"Both Mobility and Lubricants achieved their best-ever results in 2025 as we continued to focus on value over volume and disciplined performance across the portfolio."

Machteld de Haan
President, Downstream, Renewables and Energy Solutions

Financial delivery

2025 earnings [A]

Income/(loss) for the period was driven by the same factors as Adjusted Earnings and includes identified items.

Adjusted Earnings increased by \$109 million compared with 2024. This reflected higher Marketing margins (increase of \$413 million) including Mobility and Lubricants, due to improved unit margins, partly compensated by lower Sectors and Decarbonisation margins. This was partly offset by unfavourable tax movements (\$326 million).

Identified items in 2025 included net impairment charges and reversals of \$1,384 million and provisions of \$186 million, both of which included the impact of the decision not to restart construction of the planned biofuels facility at the Shell Energy and Chemicals Park in Rotterdam. These charges compare with the full year 2024, which included net impairment charges and reversals of \$1,423 million, net losses of \$386 million related to the sale of assets and charges of \$215 million related to redundancies and restructuring.

Adjusted EBITDA was driven by the same factors as Adjusted Earnings.

Prior year earnings [A]

Income/(loss) for the period was driven by the same factors as Adjusted Earnings and includes identified items.

Adjusted Earnings increased by \$573 million compared with 2023. This reflected higher Marketing margins (increase of \$483 million) including higher unit margins in Lubricants and Mobility. This was partly offset by lower Sectors and Decarbonisation margins. Adjusted Earnings also reflected lower operating expenses (decrease of \$449 million). These were partly offset by unfavourable tax movements (\$157 million) and higher depreciation charges (increase of \$142 million).



Photo: Shenzhen electric vehicle charging station, China.

Key metrics [B]

	\$ million, except where indicated		
	2025	2024	2023
Income/(loss) for the period	2,057	1,709	2,690
Identified items [B]	(1,708)	(1,990)	(254)
Adjusted Earnings* [B] [C]	3,994	3,885	3,312
Adjusted EBITDA* [C] [D]	7,993	7,476	6,337
Cash flow from operating activities	6,339	7,363	5,561
Cash capital expenditure*	1,862	2,445	5,790
Marketing sales volumes (thousand b/d)	2,753	2,843	3,045

[B] See Note 7 to the "Consolidated Financial Statements" on pages 259-267.

[C] Adjusted Earnings and Adjusted EBITDA are presented on a current cost of supplies basis.

[D] Adjusted EBITDA is without taxation and DD&A expenses.

Identified items in 2024 included net impairment charges and reversals of \$1,423 million, mainly related to an asset in the Netherlands, net losses of \$386 million related to the sale of assets, and charges of \$215 million related to redundancies and restructuring. These charges compare with the full year 2023, which included net impairment charges and reversals of \$466 million, and charges of \$113 million related to redundancies and restructuring, partly offset by gains of \$298 million related to indirect tax credits.

Adjusted EBITDA was driven by the same factors as Adjusted Earnings.

Cash flow from operating activities

Cash flow from operating activities in 2025 was primarily driven by Adjusted EBITDA and dividends (net of profits/losses) from joint ventures and associates of \$729 million. These inflows were partly offset by working capital outflows of \$609 million, tax payments of \$566 million, net outflows relating to the timing impact of payments related to emission certificates and biofuel programmes of \$310 million and non-cash cost of supplies adjustment of \$305 million.

Cash capital expenditure

Cash capital expenditure* of \$1.9 billion in 2025 included \$0.5 billion in low-carbon energy solutions, compared with \$0.8 billion in 2024.

Cash capital expenditure in low-carbon energy solutions was higher in 2024, mainly due to the spend in the biofuels facility at the Shell Energy and Chemicals Park in Rotterdam.

Our cash capital expenditure* is expected to be in the range of \$2-3 billion in 2026.

[A] All earnings amounts are shown post-tax unless otherwise stated.

* Non-GAAP measure. See page 430.

Operational performance

Marketing sales

Marketing sales volumes, which comprise hydrocarbon sales, decreased compared with 2024. This was mainly as a result of reduced sales volumes in Mobility due to portfolio changes, including the impact of divestments, and in Sectors and Decarbonisation.

Number of electric vehicle charge points

In 2025, the number of electric vehicle charge points owned or Shell-branded was almost 88,000 compared with almost 73,000 in 2024.

Strategic progress

Portfolio and business developments

Significant portfolio and business developments:

- In June 2025, we completed the acquisition of Raj Petro Specialities Pvt Ltd from the Brenntag Group. This acquisition supports our goal to strengthen our lubricants portfolio and customer base in India.
- In September 2025, we announced the decision not to restart the construction of the planned biofuels facility at the Shell Energy and Chemicals Park in Rotterdam, which had been paused in 2024.
- In May 2025, we agreed to transfer ownership of our Indonesia mobility business to a joint venture between Citadel Pacific Limited and Sefas Group [A], and we signed an agreement to sell our Mexico mobility sites [A].

[A] Transaction subject to completion.

Business and property

Mobility

Shell Mobility is one of the world's largest mobility retailers by number of sites, with more than 40,000 Shell-branded mobility sites, including service stations, in more than 80 markets at the end of 2025. In 2025, the number of Shell-branded mobility locations fell to 42,724 from 44,109 in 2024. We operate different models across our markets, from full ownership of sites to brand licensing agreements.

We are focusing on markets that provide higher returns on investment. Following the 2024 divestment of Shell Pakistan, in 2025, we agreed to transfer ownership of the Indonesia mobility business, including 200 sites, to a new joint venture between Citadel Pacific and Sefas Group. We also agreed to sell the Mexico mobility businesses. To increase market focus we will spend 80% of cash capital expenditure in 10 key markets that account for the majority of cash flow.

Every day, around 29 million retail customers visit Shell-branded mobility sites for a range of quality fuels, electric vehicle charging, and convenience and non-fuel products and services. Through Shell Fleet Solutions, our business customers can obtain fuel cards, road services and carbon-offset offers, among other products and services.

We are expanding our convenience retail offer to cater to our customers' needs. At many of our sites, we offer convenience items, including beverages and fresh food, and services, such as lubricant changes and car washes. At the end of 2025, Shell operated around 13,000 convenience stores worldwide. We have upgraded more than 2,900 Shell-operated stores with our Shell Café premium fresh coffee and food offer since it launched in 2021.

Shell Mobility offers customers products and services, including biofuels and electric vehicle charging. At the end of 2025, we had almost 88,000 public charge points globally at Shell forecourts, on-street locations, mobility hubs and other sites, such as supermarkets.

Shell's global electric vehicle charging business is not yet profitable. However, we remain committed to investing in this sector as we anticipate future profitability. The timeline and extent of this profitability will be influenced by factors such as network accessibility, market competition, customer demand, advancements in cost-related technologies and supportive government policies.

As we work to provide low-carbon alternatives to our customers, we also continue to develop traditional fuels for drivers of internal combustion engine vehicles. Aided by our partnership with Scuderia Ferrari HP, we have concentrated on developing fuels with special formulations designed to clean engines and improve performance. An example of this is Shell V-Power. We sold fuels under the Shell V-Power brand in 71 markets in 2025.

Shell Fleet Solutions is also working to help drive decarbonisation of the transport sector by providing fuels, lubricants and digital services to customers with heavy-duty vehicles in their fleets. We have a public electric vehicle charging facility for trucks in Hamburg, Germany, which has four fast-charging stations.

We also offer drivers using heavy-duty LNG-fuelled trucks access to Shell-operated and partner networks in Europe. We have LNG refuelling sites in Austria and Hungary.

Trading and Supply

Through our main trading and supply offices in London, Houston, Singapore, Dubai, Rotterdam and Canada, we trade low-carbon fuels, refined products, chemical feedstocks and environmental products. We trade in physical and financial contracts, and have wholesale commercial fuel activities. Shell Wholesale Commercial Fuels provides fuels for transport, industry and heating – from reliable main-grade fuels to premium products. With about 180 Shell and joint-venture (including pipeline) terminals and operating in around 25 countries, our infrastructure is well positioned to make deliveries around the world.

Lubricants

Shell Lubricants has been the number one global finished lubricants supplier in terms of market share for 19 consecutive years, according to Kline & Company data for 2024. Shell lubricants are available in around 175 markets for passenger cars, motorcycles, trucks, coaches, and machinery used in manufacturing, mining, power generation, agriculture and construction.

In addition to making premium lubricants for conventional vehicles, we also make Shell E-Fluids from base oils made from natural gas at the Pearl gas-to-liquids (GTL) plant in Qatar. These base oils can be used in electric vehicles, data centres, and health care and beauty products.

See "Shell's cooling fluids certified by Intel for use in data centres worldwide" on page 56.

Our global lubricants supply chain has a network of 31 lubricants blending plants, four base oil plants (one of which we operate), 10 grease plants and five GTL base oil storage hubs. Shell Lubricants also has a strong distributor network of almost 1,600 distributors, including large-scale, large-volume multinational organisations.

Sectors and Decarbonisation

The Sectors and Decarbonisation business sells fuels, speciality products and services – including low-carbon energy solutions – to a broad range of commercial customers including the aviation, marine and agricultural sectors.

Aviation

Shell Aviation provides aviation fuel, lubricants and low-carbon solutions globally. Shell's Avelia platform is one of the world's first blockchain-powered sustainable aviation fuel (SAF) book-and-claim solutions. Avelia aims to scale SAF, reducing the life-cycle greenhouse gas (GHG) emissions of aviation and enabling greater participation in the aviation sector's decarbonisation efforts by providing wider access to the GHG benefits of SAF across the value chain.

Wider production and supply, driven by increased demand, could help lower the price point for these fuels. Since launch, Avelia has injected more than 64 million gallons of SAF into the fuel network at 18 airports around the world and supported more than 66 airlines and corporate customers in accessing the environmental attributes of SAF.



Photo: Shell Aviation supplies sustainable aviation fuel to Delta.

Marine

Shell Marine serves around 15,000 ships every year. Our customers' vessels range from ocean-going tankers to fishing boats. We supply seven types of fuel, more than 500 grades of lubricants and low-carbon solutions. Our lubricants are used in around 10,000 vessels and are available in more than 700 ports across more than 50 countries.

Shell has the world's largest LNG bunkering network with 29 locations across 13 countries. BioLNG is available at 22 of these locations across Europe and the USA. Shell Marine also supplies chemical products, and marine-related technical and digital services.

Biofuels

In line with our strategic focus on disciplined capital allocation to help ensure competitive returns, we decided in 2025 not to restart construction of the planned biofuels facility at the Shell Energy and Chemicals Park Rotterdam. Construction had been paused in 2024.

In 2025, around 10.34 billion litres of biofuels (2024: 10.37 billion litres) were blended into Shell's sales of fuels worldwide, which include the Shell share of sales made by Raízen. Raízen produced, on a 100% basis, around 2.73 billion litres of ethanol in 2025 (2024: 3.16 billion litres).

Shell and the non-operated joint venture Raízen (Shell interest 44%) are, together, one of the world's largest blenders and distributors of biofuels. Biofuels, along with natural gas, will play a key role in reducing emissions from heavy-duty transport.

Renewable natural gas (RNG), also known as biogas or biomethane, is gas derived from processing organic waste in a controlled environment until it is fully interchangeable with conventional natural gas. Shell Biogas is one of Europe's largest producers of RNG following the acquisition of Nature Energy in 2023.

Marketing data tables

Branded mobility locations [A]

	2025	2024	2023
Europe	7,285	8,227	8,346
Asia [B]	7,573	7,742	10,824
Oceania [B]	1,205	1,047	1,087
Africa	3,027	2,994	2,917
Americas [C]	23,634	24,099	23,830
Total [D]	42,724	44,109	47,004

[A] Includes different models, from full-ownership retail sites and sites operated by joint ventures, through to trademark licensing agreements; and excludes sites closed for more than six months.

[B] Asia includes Turkey; Oceania includes French Polynesia, Guam, Palau and Saipan.

[C] 2025 includes around 8,125 sites operated by the Raízen joint venture.

[D] 2025 includes 7,716 sites operated through trademark licensing agreements.

Marketing sales volumes [A][B][C]

	2025	2024	Thousand b/d 2023
Europe			
Mobility	577	611	626
Lubricants	15	16	16
Sectors and Decarbonisation	158	192	186
Total	750	819	828
Asia			
Mobility	586	594	607
Lubricants	44	40	39
Sectors and Decarbonisation	85	104	138
Total	715	738	784
Africa			
Mobility	63	63	74
Lubricants	3	2	3
Sectors and Decarbonisation	7	6	9
Total	73	71	86
Americas			
Mobility	780	790	919
Lubricants	23	23	24
Sectors and Decarbonisation	412	402	404
Total	1,215	1,215	1,347
Total product sales			
Mobility	2,006	2,057	2,226
Lubricants	85	82	82
Sectors and Decarbonisation	662	704	737
Total	2,753	2,843	3,045
Gasolines	1,240	1,282	1,321
Kerosenes	375	391	386
Gas/diesel oils	924	960	1,012
Fuel oil	21	22	23
Other products [D]	193	188	303
Total	2,753	2,843	3,045

[A] Excludes deliveries to other companies under reciprocal sale and purchase arrangements that are in the nature of exchange contracts.

[B] Includes the Shell share of Raizen's sales volumes and other joint ventures' sales volumes.

[C] Excludes sales volumes from markets where Shell operates under trademark licensing agreements.

[D] Includes LPG sales volumes of 22 thousand b/d (2024: 26 thousand b/d; 2023: 29 thousand b/d).



Shell's cooling fluids certified by Intel for use in data centres worldwide

Data centres are vital for the internet, but the rapid growth of artificial intelligence (AI) and big data has created a challenge for managing the heat generated by these centres. Without efficient cooling, servers risk overheating and this can lead to costly outages. Traditional cooling systems – air or water – consume significant energy and so alternatives are sought.

In 2025, Shell Lubricants' immersion cooling fluids became the first to earn Intel Data Center Certification for Immersion Cooling, with confirmed compatibility with 4th and 5th Gen Intel Xeon processors. The certification follows two years of rigorous testing, which demonstrated that processors remain as reliable in Shell's immersion cooling fluids as in traditional air-cooled systems.

Immersion cooling works by submerging servers and networking equipment in a non-conductive liquid that absorbs and dissipates heat far more efficiently than air. By eliminating the need for chillers, fans and evaporative cooling systems, this approach can also significantly reduce data centre floor space.

Innovation sets us apart

Shell's immersion cooling fluids, developed in our own laboratories, are already in use at Shell data centres in Houston and Amsterdam. They are PFAS-free, biodegradable to varying degrees, and suitable for hot and humid environments. The fluids also qualify for Intel's Immersion Warranty Rider, providing additional assurance for data centre operators.

This breakthrough aligns with Shell's broader strategy to invest in premium, high-value products that help customers meet emission reduction goals. As the world's leading lubricants supplier, Shell is leveraging decades of expertise in gas-to-liquids technology to deliver sustainable solutions for the growing demands of digital infrastructure. The technology can reduce energy use costs substantially, while supporting dramatic reductions in water consumption.

Photo: Shell Technology Center, Houston, USA.



Chemicals and Products

Chemicals and Products includes chemicals manufacturing plants with their own marketing network and refineries which turn crude oil and other feedstocks into a range of oil products, which are moved and marketed around the world for domestic, industrial and transport use. The segment also includes the pipeline business, trading and optimisation of crude oil, oil products and petrochemicals.

We aim to unlock more value and improve returns from our portfolio of Chemicals assets by exploring strategic and partnership opportunities in the USA. In Europe, we are also exploring the high-grading of some assets and the selective closure of others.

In 2025, Chemicals margins remained under pressure in a tough macro environment leading to continued losses in the business. Products earnings weakened due to lower contributions from trading and supply, despite improvements in refining margins.

We continued to implement our strategy through disciplined capital allocation and the high-grading of our portfolio. In 2025, we completed the divestment of the Shell Energy and Chemicals Park Singapore and sold non-core assets such as the Colonial Pipeline interest, generating \$1 billion in proceeds. We are also working to reposition our Chemicals portfolio to unlock further value.

For the business conditions relevant to Chemicals and Products, see "Market overview" on pages 25-27.

0.3

Income/(loss) for the period (\$ billion)
(2024: 1.7)

1.1

Adjusted Earnings (\$ billion)
(2024: 2.9)

5.4

Cash flow from operating activities (\$ billion)
(2024: 7.3)

1,217

Refinery processing intake (thousand b/d)
(2024: 1,344)

1,005

Product sales volumes (thousand b/d)
(2024: 1,052)

9,260

Chemicals sales volumes (thousand tonnes)
(2024: 11,875)



"In 2025, we executed several value-led moves to high-grade our portfolio and unlock further value."

Machteld de Haan
President, Downstream, Renewables and Energy Solutions

Financial delivery

2025 earnings [A]

Income/(loss) for the period was driven by the same factors as Adjusted Earnings and includes identified items.

Adjusted Earnings in 2025 decreased by \$1,883 million compared with 2024. This reflected lower Products margin (a decrease of \$972 million) driven mainly by lower margins from trading and optimisation, partly offset by higher refining margins. Adjusted Earnings also reflected lower Chemicals margins (decrease of \$604 million) and unfavourable tax movements (\$485 million). These net unfavourable movements were partly offset by lower operating expenses (decrease of \$138 million).

Identified items in 2025 included:

- net impairment charges and reversals of \$634 million and net gains from the disposal of assets of \$564 million mainly relating to gains from the sale of our interest in Colonial Enterprises, Inc.

These charges and movements compare with the full year 2024, which included net impairment charges and reversals of \$1,176 million mainly relating to assets in Singapore, charges of \$142 million related to redundancy and restructuring, and unfavourable movements of \$86 million relating to an accounting mismatch due to fair value accounting of commodity derivatives, partly offset by favourable deferred tax movements of \$114 million.

In 2025, Adjusted Earnings from Chemicals accounted for (108)%, Refining for 82% and Trading and Optimisation for 126%. The decrease in Adjusted Earnings of \$1,883 million was driven by the following:

- Products Adjusted Earnings were \$1,189 million lower than in 2024, mainly driven by lower trading and optimisation and oil sands margins and unfavourable tax movements, partly offset by higher refining margins and lower operating expenses.
- Chemicals negative Adjusted Earnings were \$693 million higher than in 2024, mainly because of lower margins and unfavourable tax movements.

Adjusted EBITDA was driven by the same factors as Adjusted Earnings.

Prior year earnings [A]

Income/(loss) for the period was driven by the same factors as Adjusted Earnings and includes identified items.

Adjusted Earnings in 2024 decreased by \$683 million compared with 2023. This reflected lower Products margins (a decrease of \$1,832 million), mainly driven by lower refining margins and unfavourable tax movements (\$248 million). These were partly offset by lower operating expenses (decrease of \$812 million) and higher Chemicals margins (increase of \$602 million).

Identified items in 2024 included:

- net impairment charges and reversals of \$1,176 million mainly relating to assets in Singapore;
- charges of \$142 million related to redundancy and restructuring; and
- unfavourable movements of \$86 million relating to an accounting mismatch due to fair value accounting of commodity derivatives, partly offset by favourable deferred tax movements of \$114 million.

Key metrics [B]

\$ million, except where indicated

	2025	2024	2023
Income/(loss) for the period	262	1,671	1,204
Identified items [B]	(377)	(1,177)	(2,135)
Adjusted Earnings* [B] [C]	1,051	2,934	3,616
Adjusted EBITDA* [C] [D]	4,880	6,783	7,489
Cash flow from operating activities	5,366	7,253	7,513
Cash capital expenditure*	3,063	3,290	3,014
Chemicals manufacturing plant utilisation (%)	78%	76%	68%
Refinery utilisation (%)	92%	85%	85%
Refinery processing intake (thousand b/d)	1,217	1,344	1,349
Product sales volumes (thousand b/d)	1,005	1,052	1,078
Chemicals sales volumes (thousand tonnes)	9,260	11,875	11,245

[B] See Note 7 to the "Consolidated Financial Statements" on pages 259-267.

[C] Adjusted Earnings and Adjusted EBITDA are presented on a current cost of supplies basis.

[D] Adjusted EBITDA is without taxation and DD&A expenses.

These charges and movements compare with the full year 2023, which included net impairment charges and reversals of \$2,195 million mainly relating to the Chemicals assets in Singapore, and charges of \$82 million related to redundancy and restructuring partly offset by favourable movements of \$214 million relating to an accounting mismatch due to fair value accounting of commodity derivatives.

In 2024, Adjusted Earnings from Chemicals accounted for (15)%, Refining for 34% and Trading and Optimisation including pipelines for 81%. The decrease in Adjusted Earnings of \$683 million was driven by the following:

- Products Adjusted Earnings were \$1,818 million lower than in 2023, mainly driven by lower refining and oil sands margins, unfavourable tax movements and higher depreciation partly offset by lower operating expenses.
- Chemicals negative Adjusted Earnings were \$1,135 million lower than in 2023, mainly because of higher margins and lower operating expenses, and lower depreciation.

Adjusted EBITDA was driven by the same factors as Adjusted Earnings.

Cash flow from operating activities

Cash flow from operating activities in 2025 was primarily driven by Adjusted EBITDA, net inflows related to the timing impact of payments for emission certificates and biofuel programmes of \$1,260 million and dividends (net of profits) from joint ventures and associates of \$404 million. These inflows were partly offset by net cash outflows relating to commodity derivatives of \$761 million and non-cash cost of supplies adjustment of \$567 million.

Shell's policy is to settle the inter-segment use of tax attributes between business segments. This settlement is usually made in cash but in certain instances there is no cash settlement. In 2025, deferred tax assets of the Integrated Gas (\$211 million) and Corporate (\$89 million) segments were used by the Chemicals and Products (\$300 million) segment, for which no cash settlement was made.

Cash capital expenditure

Cash capital expenditure* decreased by \$0.2 billion in 2025 to \$3.1 billion mainly because of lower spend in Singapore and China. Our cash capital expenditure* is expected to be around \$3 billion in 2026.

[A] All earnings amounts are shown post-tax unless otherwise stated.

* Non-GAAP measure. See page 430.

Operational performance

Chemicals manufacturing plant utilisation

Utilisation is defined as the actual use of the plants as a percentage of the rated capacity. Chemicals manufacturing plant utilisation of 78% was 2 percentage points higher than in 2024.

Refinery utilisation

Utilisation is defined as the actual use of the plants as a percentage of the rated capacity. Refinery utilisation of 92% was seven percentage points higher than in 2024, mainly due to lower planned maintenance in 2025.

Chemicals and Products sales

Chemicals sales volumes were 22% lower than in 2024, mainly due to the portfolio impact from the divestment of Shell Energy and Chemicals Park Singapore divestment and lower polyethylene volumes.

Products sales volumes were 4% lower than in 2024 due to lower Trading sales volumes in Asia partly offset by increases in Europe.

Strategic progress

Portfolio and business developments

Significant portfolio and business developments:

- In January 2025, CNOOC and Shell Petrochemicals Company Limited (CSPC), a 50:50 joint venture between Shell Nanhai B.V. and CNOOC Petrochemicals Investment Ltd, took the final investment decision to expand its petrochemical complex in Daya Bay, Huizhou, south China.
- In April 2025, we completed the previously announced sale of Shell Energy and Chemicals Park Singapore to CAPGC Pte. Ltd. (CAPGC), a joint venture between Chandra Asri Capital Pte. Ltd. and Glencore Asian Holdings Pte. Ltd.
- In July 2025, we completed the sale of our 16.1% interest in Colonial Enterprises Inc. to Colossus AcquireCo LLC.

Business and property

Chemicals

We operate chemical plants worldwide and have a balance of locations, feedstocks and products. Products made from chemicals are used in everyday life, including in medical equipment, construction, transport, electronics, agriculture and sports. Our plants produce a range of base chemicals, including ethylene, propylene and aromatics, and intermediate chemicals, such as styrene monomer, propylene oxide, solvents, linear alpha olefins, detergent alcohols, ethylene oxide, ethylene glycol and polyethylene.

We have the capacity to produce around 6.7 million tonnes of ethylene a year (including the Shell share of capacity entitlement (offtake rights) of joint ventures and associates, which may be different from nominal equity interest).

Shell Polymers Monaca, our Pennsylvania chemical facility, experienced intermittent utilisation during 2025. This has been addressed and we expect improved utilisation in 2026.

Products – Refining and Trading

Refining

We have direct interests in seven refineries, with a total capacity to process 1.4 million barrels of crude oil a day. The distribution of our refining capacity is 64% in Europe, 32% in the Americas and 4% in Asia.

We took the final investment decision (FID) in 2024 to convert the hydrocracker of the Wesseling site at the Energy and Chemicals Park Rheinland in Germany into a production unit for Group III base oils. Crude oil processing ended at the Wesseling site in 2025 and will continue at the Godorf site.

See "Rheinland decarbonises operations and expands hydrogen production" on page 63.

Trading and Supply

Through our main trading offices in London, Houston, Singapore, Dubai, The Bahamas, Rotterdam and Canada, we trade crude oil, low-carbon fuels, refined products, chemical feedstocks and environmental products. We trade in physical and financial contracts, lease storage and transportation capacities, and manage global shipping activities.

Our global network of supply and distribution activities and shipping and maritime capabilities enables the safe delivery of products under our contracts and this includes supplying feedstock for our refineries and chemical plants, and finished products such as gasoline, diesel and aviation fuel to our Marketing segment and customers.

Pipelines

We own and operate three tank farms across the USA through Shell Pipeline Company LP (Shell interest 100%). It transports around 1.5 billion barrels of crude oil, refined products and chemicals a year through around 5,400 kilometres of pipelines in the Gulf of America and eight US states.

Our pipelines carry more than 40 types of crude oil and more than 20 grades of fuel including petrol, diesel and aviation fuel, and chemicals including ethylene.

We own, operate, develop and acquire pipelines and other midstream and logistics assets. Our assets include interests in entities that own crude oil and refined products pipelines and terminals that serve as key infrastructure to:

- transport onshore and offshore crude oil production to US Gulf Coast and Midwest refining markets; and
- deliver refined products from those markets to major demand centres.

Our assets also include interests in entities that own natural gas and refinery gas pipelines that transport offshore natural gas to market hubs and deliver refinery gas from refineries and plants to chemical sites along the US Gulf Coast.

Oil sands

In November 2025, we completed the previously announced agreement with Canadian Natural Resources Limited to swap our remaining 10% interest in the Albion mining and extraction operations in exchange for an additional 10% interest in the Scotford upgrader and Quest Carbon Capture and Storage (CCS) facility. Following the completion of this swap, Shell holds a 20% interest in the Scotford upgrader and Quest CCS facility and no longer has any oil sands activities.

Quest CCS captures about 1 million tonnes per year of CO₂ from the hydrogen manufacturing units within the upgrader. Since opening in 2015, Quest CCS has safely stored more than 9 million tonnes of CO₂.

Chemicals and Products data tables

The tables below reflect Shell subsidiaries and instances where Shell owns the crude oil or feedstocks processed by a refinery. Other joint ventures and associates are only included where explicitly stated.

Products sales volumes [A][B]

	Thousand b/d		
	2025	2024	2023
Europe	560	507	560
Asia	144	248	240
Americas	301	297	278
Total	1,005	1,052	1,078
Gasolines	144	141	154
Kerosenes	110	94	104
Gas/diesel oils	289	321	346
Fuel oil	147	200	221
Other products [C]	315	296	252
Total	1,005	1,052	1,078

[A] Excludes deliveries to other companies under reciprocal sale and purchase arrangements, which are in the nature of exchanges. Sales of condensate are included.

[B] Certain contracts are held for trading purposes and reported net rather than gross. The effect in 2025 was a reduction in refining and trading sales of around 1,304 thousand b/d (2024: 1,286 thousand b/d; 2023: 1,202 thousand b/d).

[C] Includes LPG sales volumes of 56 thousand b/d (2024: 54 thousand b/d; 2023: 55 thousand b/d).

Cost of crude oil processed or consumed [A]

	\$/barrel		
	2025	2024	2023
Total	66.78	77.97	71.13

[A] Includes Upstream and Integrated Gas margins on crude oil supplied by Shell subsidiaries, joint ventures and associates.

Crude distillation capacity [A]

	Thousand b/stream day [B]		
	2025	2024	2023
Europe	868	975	975
Asia	59	237	237
Africa	—	—	—
Americas	435	435	435
Total	1,362	1,646	1,646

[A] Average operating capacity for the year, excluding mothballed capacity.

[B] Stream day capacity is the maximum capacity with no allowance for downtime.

Crude oil processed [A]

	Thousand b/d		
	2025	2024	2023
Europe	726	742	732
Asia	37	165	168
Americas	369	359	322
Total	1,132	1,266	1,222

[A] Includes natural gas liquids, share of joint ventures and associates and processing for others.

Refinery processing intake [A]

	Thousand b/d		
	2025	2024	2023
Europe	738	742	764
Asia	37	166	171
Americas	442	437	414
Total	1,217	1,344	1,349

[A] Includes crude oil, natural gas liquids and feedstocks processed in crude distillation units and in secondary conversion units.

Refinery processing outturn [A]

	Thousand b/d		
	2025	2024	2023
Gasolines	416	486	489
Kerosenes	134	162	168
Gas/diesel oils	454	506	516
Fuel oil	79	80	88
Other	217	186	149
Total	1,299	1,419	1,410

[A] Excludes own use and products acquired for blending purposes.

Manufacturing plants at December 31, 2025

Refineries

				Thousand barrels/stream day, 100% capacity [B]			
	Location	Asset class	Shell interest (%) [A]	Crude distillation capacity	Thermal cracking/visbreaking/coking	Catalytic cracking	Hydro-cracking
Europe							
Germany	Miro [C]	■	32	313	40	96	—
	Rheinland	■ ●	100	235	16	—	75
	Schwedt [C]	■	38	234	46	57	—
Netherlands	Pernis	■ ●	100	447	—	53	104
Americas							
Argentina	Buenos Aires [D]	● ◆	44	112	14	22	—
Canada							
Alberta	Scotford	■	100	100	—	—	83
Ontario	Sarnia	◆	100	85	5	21	10
USA							
Louisiana	Norco	■	100	250	29	119	44

[A] Shell interest is rounded to the nearest whole percentage point; Shell share of production capacity may differ.

[B] Stream day capacity is the maximum capacity with no allowance for downtime.

[C] Not operated by Shell.

[D] Owned through Raizen joint venture.

- Integrated refinery and chemical complex
- Refinery complex with cogeneration capacity
- ◆ Refinery complex with chemical unit(s)

Chemicals data tables

The tables below reflect Shell subsidiaries and instances where Shell owns the crude oil or feedstocks processed by a refinery. Other joint ventures and associates are only included where explicitly stated.

Ethylene capacity [A]

	Thousand tonnes/year		
	2025	2024	2023
Europe	1,693	1,713	1,710
Asia [B]	1,381	2,542	2,542
Americas [C]	3,901	3,821	3,821
Total	6,975	8,076	8,073

[A] In 2025, ethylene capacity includes the Shell share of capacity entitlement (offtake rights) of joint ventures and associates, which may be different from nominal equity interest.

[B] Includes Shell Energy and Chemicals Park Singapore, the sale of which was completed in April 2025.

[C] Shell Polymers Monaca, which began operations in November 2022, was not fully functional during 2023 due to operational and start-up challenges which were resolved during the first quarter of 2024. In 2025, an additional defect intermittently impacted utilisation. This has subsequently been corrected.

Chemicals sales volumes [A]

	Thousand tonnes/year		
	2025	2024	2023
Europe			
Base chemicals	1,947	2,113	1,741
Intermediates and other chemical products	1,815	1,889	1,848
Total	3,762	4,001	3,589
Asia			
Base chemicals	242	1,198	1,190
Intermediates and other chemical products	564	1,744	1,917
Total	806	2,943	3,107
Americas			
Base chemicals	1,297	1,366	1,508
Intermediates and other chemical products	3,395	3,566	3,041
Total	4,692	4,932	4,549
Total product sales			
Base chemicals	3,486	4,677	4,439
Intermediates and other chemical products	5,774	7,199	6,806
Total	9,260	11,875	11,245

[A] Excludes feedstock trading and by-products.

Major chemical plants [A]

		Thousand tonnes/year, Shell share capacity [B]					
	Location	Ethylene	Polyethylene	Styrene monomer	Ethylene glycol	Higher olefins [C]	Additional products
Europe							
Germany	Rheinland	307	—	—	—	—	A
Netherlands	Moerdijk	971	—	815	153	—	A, I
UK	Mossmorran [D] [E]	415	—	—	—	—	O
Asia							
China	Nanhai [D]	1,100	605	645	415	—	A, I
Americas							
Canada	Scotford	—	—	519	461	—	A, I
USA	Monaca	1,500	1,600	—	—	—	
	Deer Park	889	—	—	—	—	A, I
	Geismar	—	—	—	400	1,390	I
	Norco	1,512	—	—	—	—	A
Total		6,694	2,205	1,979	1,429	1,390	

[A] Major chemical plants are large integrated chemical facilities, typically producing a range of chemical products from an array of feedstocks.

[B] Shell share of capacity of subsidiaries, joint arrangements and associates (Shell- and non-Shell-operated), excluding capacity of the Infineum additives joint ventures.

[C] Higher olefins are linear alpha and internal olefins (products range from C4 to C2024).

[D] Not operated by Shell. Shell has 50% of capacity rights.

[E] In January 2026, ExxonMobil closed the Fife Ethylene Plant (Mossmorran) after announcing this in November 2025.

A Aromatics, lower olefins

I Intermediates

O Other

Other chemicals locations [A]

	Location	Products
Europe		
Germany	Karlsruhe	A
	Schwedt	A
	Rotterdam	A, I, O
Netherlands		
Americas		
Argentina	Buenos Aires	I
Canada	Sarnia	A, I

[A] Other chemical locations reflect locations with smaller chemical units, typically serving more local markets.

A Aromatics, lower olefins

I Intermediates

O Other



Rheinland decarbonises operations and expands hydrogen production

Shell's Energy and Chemicals Park Rheinland is delivering one of its most ambitious projects to date, marking a decisive step toward low-carbon products and advanced technologies. At Wesseling, the long-standing hydrocracker unit – once central to producing diesel and jet fuel – is being dismantled to make way for a highly electrified base oils plant.

This new facility is expected to produce approximately 300,000 tonnes of Group III base oils annually, meeting around 40% of Germany's demand and 9% of the EU's. These premium base oils are essential for high-performance lubricants, including engine and transmission oils, as well as fluids for electric vehicles – markets expected to grow significantly.

The development is not only about capacity but also about emissions reduction and operational excellence. By ceasing crude oil processing at Wesseling and introducing electrification, Shell expects to cut Scope 1 and Scope 2 emissions by about 620,000 tonnes per year. This substantial reduction supports Shell's strategy to deliver more value with less emissions.

The facility's operators are undergoing rigorous training using advanced simulators, enabling them to identify potential issues before start-up and reduce commissioning time.

Advancing hydrogen production

Beyond base oils, Rheinland is also advancing renewable hydrogen production through the REFHYNE II project. Following the final investment decision in 2024, construction is under way on a 100-megawatt proton-exchange membrane electrolyser. Scheduled to begin operations in 2027, REFHYNE II will produce up to 44 tonnes of renewable hydrogen daily, powered by renewable electricity secured through long-term agreements. This hydrogen will help decarbonise site operations.

The scale and complexity of these developments are vast: thousands of pipes are being reconfigured while maintaining ongoing production. When complete in 2028, the Rheinland base oils plant is expected to be the largest in Germany and among the top 10 in Europe.

These achievements highlight Rheinland's evolution from a traditional refinery into a cutting-edge energy and chemicals hub, combining technical innovation, sustainability and operational excellence to meet the demands of a changing world.



1. Boats at the Shell Energy and Chemicals Park Rheinland, Cologne-Godorf, Germany.
2. Wesseling site, part of the Shell Energy and Chemicals Park, Rheinland.



Renewables and Energy Solutions

The Renewables and Energy Solutions segment includes renewable power generation; the marketing, trading and optimisation of power and pipeline gas; and carbon credits. The segment also includes the production and marketing of hydrogen; development of commercial carbon capture and storage hubs; investment in nature-based projects that compensate for carbon emissions; and Shell Ventures, which invests in or works with start-ups and early-stage businesses to help them scale up and grow.

We are focusing on high-grading our Renewables and Energy Solutions portfolio through disciplined investment as we work to unlock value in power and low-carbon solutions. This will support our climate-related targets and ambition, and position us for growth in hydrogen and carbon capture and storage (CCS).

In 2025, we divested a number of lower-return assets, withdrawing from projects like Atlantic Shores and Scotwind, while also diluting parts of our Savion portfolio. This allows us to reallocate capital to higher-return segments of the power value chain. These steps are aligning our portfolio with our increased focus on flexible power generation and trading.

The Northern Lights joint venture in Norway took a final investment decision to progress Phase 2 of the development, and received its first cargo of CO₂, injecting it beneath the seabed. We also acquired RISEC Holdings, adding a 609 MW combined-cycle gas plant in the USA.

Earnings improved in 2025 with higher generation and energy marketing margins, along with lower operating expenses as a result of portfolio changes and continued exercising of cost discipline.

For the business conditions relevant to Renewables and Energy Solutions, see "Market overview" on pages 25-27.

(0.5)

Income/(loss) for the period (\$ billion)
(2024: (1.2))

0.2

Adjusted Earnings (\$ billion)
(2024: (0.5))

0.6

Cash flow from operating activities (\$ billion)
(2024: 3.8)

290

External power sales (terawatt hours)
(2024: 306)

626

Sales of pipeline gas to end-use customers (terawatt hours)
(2024: 652)



"We continued to high-grade our portfolio and bring our power strategy to life through disciplined execution."

Machteld de Haan
President, Downstream, Renewables and Energy Solutions

Financial delivery

2025 earnings [A]

Income/(loss) for the period was driven by the same factors as Adjusted Earnings and includes identified items.

Adjusted Earnings in 2025 increased by \$669 million compared with 2024. This reflected lower operating expenses (decrease of \$279 million) and higher margins (increase of \$229 million), mainly due to higher generation and energy marketing margins.

Identified items in 2025 included impairment charges and reversals of \$334 million and unfavourable movements of \$299 million relating to the fair value accounting of commodity derivatives. These charges and unfavourable movements compare with the full year 2024 which included net impairment charges and reversals of \$1,085 million mainly relating to renewable generation assets in North America, partly offset by favourable movements of \$300 million relating to the fair value accounting of commodity derivatives and a net gain on sale of assets of \$94 million.

As part of Shell's normal business, commodity derivative hedge contracts are entered into for the mitigation of economic exposures on future purchases, sales and inventory.

Adjusted Earnings were \$172 million in 2025. Adjusted Earnings contributions from Energy Marketing and Trading and Optimisation accounted for 333% of Adjusted Earnings, partly offset by negative contributions from Renewable Power Generation, Hydrogen, CCS, Nature Based Solutions (NBS) and Shell Ventures of (233)%.

Adjusted EBITDA was driven by the same factors as Adjusted Earnings.

Prior year earnings [A]

Income/(loss) for the period was driven by the same factors as Adjusted Earnings and includes identified items.

Adjusted Earnings in 2024 decreased by \$1,253 million compared with 2023. This reflected lower margins (decrease of \$1,719 million), mainly from trading and optimisation primarily in Europe due to lower volatility. This was partly offset by lower operating expenses (decrease of \$632 million).

Identified items in 2024 included net impairment charges and reversals of \$1,085 million, mainly related to renewable generation assets in North America, and partly offset by favourable movements of \$300 million relating to an accounting mismatch due to fair value accounting of commodity derivatives, and a net gain on sale of assets of \$94 million. These net charges and favourable movements compare with 2023, which included favourable movements of \$2,756 million due to the fair value accounting of commodity derivatives, partly offset by net impairment charges and reversals of \$669 million. As part of Shell's normal business, commodity derivative hedge contracts are entered into for the mitigation of economic exposures on future purchases, sales and inventory.

Adjusted Earnings were a loss of (\$497) million in 2024. Adjusted Earnings from Renewable Power Generation, Hydrogen, CCS, NBS and Shell Ventures accounted for 146% of 2024 negative Adjusted Earnings. These were partly offset by positive Adjusted Earnings contributions from Energy Marketing and Trading and Optimisation (46%).

Adjusted EBITDA was driven by the same factors as Adjusted Earnings.

Key metrics [B]

	\$ million, except where indicated		
	2025	2024	2023
Income/(loss) for the period	(489)	(1,229)	3,089
Identified items [B]	(661)	(732)	2,333
Adjusted Earnings* [B] [C]	172	(497)	756
Adjusted EBITDA* [C] [D]	764	(22)	1,481
Cash flow from operating activities	623	3,798	2,984
Cash capital expenditure*	1,866	2,549	2,681
External power sales (terawatt hours) [E]	290	306	279
Sales of pipeline gas to end-use customers (terawatt hours) [F]	626	652	738

[B] See Note 7 to the "Consolidated Financial Statements" on pages 259-267.

[C] Adjusted Earnings and Adjusted EBITDA are presented on a current cost of supplies basis.

[D] Adjusted EBITDA is without taxation and DD&A expenses.

[E] Physical power sales to third parties; excluding financial trades and physical trade with brokers, investors, financial institutions, trading platforms and wholesale traders.

[F] Physical natural gas sales to third parties; excluding financial trades and physical trade with brokers, investors, financial institutions, trading platforms and wholesale traders. Excluding sales of natural gas by other segments and LNG sales.

Cash flow from operating activities

Cash flow from operating activities was primarily driven by Adjusted EBITDA and working capital inflows of \$508 million. These inflows were partly offset by net cash outflows related to derivatives of \$657 million.

Cash capital expenditure

Within cash capital expenditure, \$1.5 billion was in low-carbon energy solutions. This includes Renewable Power Generation, Environmental Solutions, Hydrogen and CCS.

In 2024, cash capital expenditure included \$1.6 billion in low-carbon energy solutions. Lower cash capital expenditure in 2025 was mainly a result of the RISEC Holdings acquisition recognised in December 2024.

Our cash capital expenditure* is expected to be in the range of \$2-3 billion in 2026.

See page 81 of "Less emissions".

Operational performance

External power sales

In 2025, our external power sales declined compared with 2024, primarily due to lower demand in the US markets and our strategic choice to prioritise value over volume by focusing on higher-margin sales. This was partly offset by increased sales to direct customers and aggregators in Europe.

Sales of pipeline gas to end-use customers

In 2025, the decrease in our sales of pipeline gas to end-use customers was mainly driven by the decision to prioritise value over volume, focusing on higher-margin sales.

[A] All earnings amounts are shown post-tax unless otherwise stated.

* Non-GAAP measure. See page 430.

Strategic progress

Portfolio and business developments

Key portfolio and business developments:

- In January 2025, we completed an agreement to acquire RISEC Holdings, LLC, which owns a 609 MW two-unit combined-cycle gas turbine power plant in Rhode Island, USA.
- In March 2025, the Northern Lights joint venture (Shell interest 33.3%) took an FID to move forward with Phase 2 of the Northern Lights development.
- In May 2025, we signed a new Corporate Power Purchase Agreement (CPPA) with Google, which extends the lifespan of the NoordzeeWind offshore wind farm in the Netherlands.
- In June 2025, we completed the divestment of 100% Shell interest in Inspire Energy Capital, LLC, a B2C energy business in the USA, to Rhythm Energy, Inc.
- In July 2025, Shell subsidiary Savion and a fund managed by the Ares Infrastructure Opportunities strategy formed Tango Holdings, LLC, (Shell interest 20%), a joint venture to manage five assets with 496 MW capacity of Savion-developed solar power in the USA.
- In September 2025, we sold 100% Shell share of a cluster of eight ready-to-build Italian solar projects to Gruppo Undo, Italy.
- In September 2025, Google selected Shell as its renewable energy manager in the UK, leveraging Shell's trading and battery capabilities to support Google's decarbonisation goals.
- In October 2025, we voluntarily withdrew from Atlantic Shores Offshore Wind, LLC, in the USA, assigning our 50% outstanding membership interest to our existing joint-venture partner, EDF-RE Offshore Development, LLC.
- In November 2025, as part of the Scotwind leasing round, we and ScottishPower Renewables (SPR) agreed to exchange our 50% stakes in two offshore wind projects. SPR took full ownership of Marram Wind, acquiring our share. We took SPR's share in Campion Wind, taking full ownership which we subsequently terminated, and we returned the lease to Crown Estate Scotland.
- In November 2025, we completed the sale of our 49% interest in Cleantech Renewable Assets Pte Ltd to our joint-venture partner Keppel Ltd.

Business and property

We are maximising the value of our platforms as we continue to high-grade our portfolio and prioritise business models that deliver robust returns, and help us provide effective solutions for our customers.

In response to ongoing sector challenges, including supply chain disruptions, regulatory constraints, margin pressure, market volatility and asset impairments in North America and Europe, we have sharpened our focus on value delivery.

As part of this strategic refresh, we decided to rebalance capital allocation towards energy storage and flexible generation, in support of an increased focus on power trading.

In 2025, we progressed execution of this strategy by reshaping our asset base through divestments and dilutions, scaling flexible generation through acquisitions and leasehold commitments, increased capital discipline and enhancing trading capability. This repositioning supports our ambition to streamline our power portfolio to be more resilient, performance-driven and adaptive to evolving market dynamics.

Energy marketing

We provide electricity and smart energy solutions to commercial, industrial and residential customers. We do this through direct electricity sales, storage solutions and energy optimisation services. Our largest markets for commercial and industrial customers are Australia, Europe and the USA. In Australia, we are one of the largest commercial and industrial retailers of electricity in the market.

Trading and optimisation

We trade and optimise power, pipeline gas and carbon credits from our own assets and from third parties. We have a gas and power trading presence in key markets, including the Americas, Europe, Australia and Asia. We work with Shell businesses across regions to offer energy solutions that can help our customers decarbonise.

Renewable power generation

We enable renewable power generation by owning and participating in joint ventures for and operating solar plants, primarily in India, the USA and Europe, as well as wind farms, mainly in Europe. We are maximising the value of our platforms and continue to high-grade our power portfolio.

In the first quarter of 2025, Shell subsidiary Savion achieved full commercial operation of two solar facilities in the USA: the 111 MW Martin County Solar Project in Kentucky, developed on a reclaimed coal mine site, and the 100 MW Kiowa County Solar Project in Oklahoma.

In July 2025, Savion established Tango Holdings, LLC, a joint venture with a fund managed by Ares Infrastructure Opportunities. The venture will oversee 496 MW of solar capacity. As part of the agreement, Savion transferred majority ownership of the assets to the joint venture, while retaining a 20% minority interest and operational management responsibilities. Tango includes equity interests in the Martin County and Kiowa County projects, as well as three additional solar projects currently under construction.

This is an example of how Shell selectively develops renewable generation projects and reduces ownership as assets mature, supporting efficient scale-up, enhanced capital returns and disciplined capital allocation.

We also made strategic decisions to exit certain offshore wind projects. In October 2025, we withdrew from Atlantic Shores Offshore Wind, transferring our 50% interest to EDF-RE Offshore Development.

As part of the Scotwind leasing round in the UK and following an internal review, in November 2025, we and SPR agreed to exchange our 50% stakes in two offshore wind projects. SPR took full ownership of Marram Wind, acquiring our share. We took SPR's share in Campion Wind, taking full ownership which we subsequently terminated, and we returned the lease to Crown Estate Scotland.

We also divested Cleantech Renewable Assets in November 2025, a solar platform operating in India and Southeast Asia.

These actions reflect our focus on high-grading the portfolio and prioritising projects that deliver the strongest value.

At the end of 2025, our share of renewable power generation capacity was 4.2 GW in operation and 1.9 GW in development. Our renewable power generation capacities are listed in the following tables:

Renewable power generation capacity in operation and in development as of December 31, 2025 – by region

Location	In operation [A]		In development [B]	
	100% capacity (MW)	Shell interest (MW)	100% capacity (MW)	Shell interest (MW)
Asia	2,643	2,575	1,311	1,227
Europe	1,881	1,141	917	613
Americas	676	256	285	57
Australia	120	120	–	–
Other	126	126	8	8
Total	5,447	4,219	2,521	1,905

Renewable power generation capacity in operation and in development as of December 31, 2025

	2025	2024	2023
Renewable power generation capacity (Shell interest - gigawatts):			
In operation [A]	4.2	3.4	2.5
In development [B]	1.9	4.0	4.1

[A] Renewable generation capacity post commercial operation date.

[B] Renewable generation capacity under construction and/or committed for sale under long-term offtake agreements PPA.

Renewable power generation capacity in development decreased compared with 2024 due to transfers to capacity in operation, withdrawal from the Atlantic Shores Offshore Wind project, and other dilution in ownership interests and divestments.

Hydrogen

Hydrogen can help reduce emissions for our customers in sectors that are hard to decarbonise, such as heavy industry and heavy-duty road transport. We can also use it to help decarbonise our own assets. Shell is part of joint ventures and alliances that have built electrolyzers and hydrogen filling stations. We have also participated in feasibility studies that aim to show the viability of a global import and export market for hydrogen.

When it comes to developing hydrogen investment opportunities, we aim to do so where we see adjacencies with our integrated business value chain and where we believe there are pathways to attractive returns. Since 2021, we have operated an electrolyser (REFHYNE I, Shell interest 100%) in Germany, which produces hydrogen using electricity from renewable sources.

In 2022, we took an FID to build Holland Hydrogen I in the Netherlands. Construction is progressing well, and we expect to start commissioning in late 2026, with production ramp-up in 2027.

In July 2024, we took the final investment decision to build REFHYNE II, a 100 MW electrolyser to produce renewable hydrogen in Germany. We plan to use this hydrogen to partially decarbonise the Shell Energy and Chemicals Park Rheinland.

In November 2025, we signed two separate power purchase agreements (PPAs) in Germany with Nordsee One GmbH and Solarkraftwerk Halenbeck-Rohlsdorf I/II GmbH to secure a significant proportion of the renewable electricity needed to power the REFHYNE II facility. The electrolyser is scheduled to begin operating in 2027.

Carbon capture and storage

Shell has operational CCS projects in Canada, Australia and Norway. Together with partners, we are developing CCS projects in Europe and Canada and we continue to explore other CCS opportunities around the world. We report existing CCS operations that help decarbonise our own assets in the segment where the relevant asset sits.

We also offer carbon capture, transport and storage to our customers as we seek to help them decarbonise, including through our involvement in the Northern Lights project, which is the world's first commercial project to deliver cross-border CO₂ transport and storage as a service.

See "Northern Lights CCS venture achieves key milestones" on page 68.

Nature and environmental solutions

Through the Nature Based Solutions (NBS) business and the Environmental Products Trading Business (EPTB), we provide carbon credits to our customers. NBS invests in projects that conserve, enhance and restore ecosystems – such as forests, grasslands and wetlands – to prevent GHG emissions or reduce atmospheric CO₂ levels.

Through EPTB, we develop, source, offtake, trade and supply environmental products across compliance and voluntary markets. This includes working with our other businesses such as Integrated Gas or Marketing to provide integrated energy solutions to customers.

Shell Ventures

Through Shell Ventures we invest in or work with start-ups and other early-stage businesses to help them scale and grow. We invest in companies that work on solutions to reduce emissions, electrify energy systems, gain data-based insights and provide innovative consumer solutions. We also invest in technologies and companies that create value for our core businesses by improving efficiency, enhancing operational safety and delivering greater value to our customers.

Investments

Within R&ES, we maintain an integrated business model with trading and optimisation to help us manage our value delivery. Our investments in low-carbon solutions are subject to financial modelling and stress-testing, due diligence and risk assessments to help us allocate our capital to the most attractive low-carbon projects and opportunities.



Northern Lights CCS venture achieves key milestones

Our Northern Lights joint venture in Norway – the world's first carbon capture and storage (CCS) project to offer commercial carbon transport and storage as a service – achieved several milestones in 2025. The first deliveries of CO₂ arrived on ships that Shell helped develop, and Northern Lights made the first injection of CO₂ under the seabed. The final investment decision on the next phase of the project was also taken.

As part of our strategy to deliver more value with less emissions, we are investing in CCS projects to help decarbonise our own operations and those of our customers. The Intergovernmental Panel on Climate Change and the International Energy Agency recognise that CCS is essential for achieving net-zero emissions, particularly for carbon-intensive industries like cement and steel. For Shell, projects like Northern Lights are central to unlocking CCS potential and supporting our customers in hard-to-abate sectors.

First arrival and injection of CO₂

In August 2025, the Northern Lights joint venture (Shell interest 33.3%) with Equinor and TotalEnergies completed the world's first cross-border commercial carbon transport and storage service, injecting CO₂ collected from a cement factory 450 kilometres away into an aquifer beneath the North Sea. Northern Lights currently has the capacity to store around 1.5 million tonnes of CO₂ per year, receiving liquefied CO₂ from customers across Europe.

To transport the CO₂ to Norway, Shell engineers designed two of the largest liquefied carbon carriers in the world – the 130-metre-long Northern Pathfinder and Northern Pioneer. Each vessel can transport 7,500 cubic metres of CO₂ per voyage, equivalent to three Olympic-sized swimming pools. Powered mainly by LNG, the ships also feature wind-assisted rotor sails and air lubrication systems, reducing carbon intensity by about 34% compared with conventional ships.

1. Northern Pioneer arriving at the terminal in Øygarden. Credit: NIJ – Ruben Soltvedt.

2. The Northern Lights receiving terminal in Norway.

Phase 2 decision made

With its flexible, ship-based model, Northern Lights is uniquely positioned to serve a growing network of customers across Europe. Captured CO₂ will be shipped to Øygarden, then piped 100 km offshore for permanent storage 2,600 metres under the North Sea. The venture has agreements with Yara and Ørsted to transport and store CO₂ from facilities in the Netherlands and Denmark.

In March 2025, the final investment decision for Phase 2 was announced. Under expansion plans expected to be completed in 2028, Northern Lights will scale up transport and storage capacity from 1.5 million tonnes to at least 5 million tonnes annually – equivalent to the emissions of more than 1 million cars. Swedish energy provider Stockholm Exergi has already signed up for the transportation and storage of up to 900,000 tonnes of CO₂ annually from 2028.

Northern Lights demonstrates how Shell is leveraging its technological capabilities to build scalable businesses across lower-carbon platforms, including low-carbon fuels, hydrogen, carbon capture and storage, and power from gas-fired and renewable energy [A].

[A] Gas is a lower-carbon alternative to coal in power generation.





Corporate

The Corporate segment covers the non-operating activities supporting Shell. It comprises Shell's holdings and treasury organisation, headquarters and central functions, self-insurance activities and centrally managed longer-term innovation portfolio.

All finance expense, income and related taxes for Shell, which is headquartered in London, are included in the Corporate results for the period rather than the business results for the period. Most headquarter and central function costs are recovered from the business segments. Costs that are not recovered or relate to centrally managed activities are retained in Corporate.

The Holdings and Treasury organisation manages many of our corporate entities. It is the point of contact between Shell and external capital markets. For example, it raises debt instruments and conducts foreign exchange transactions. Treasury centres in London and Singapore support these activities.

Shell's longer-term innovation portfolio is managed centrally and is reported as part of the Corporate segment. Other innovation portfolio activities are reported in the business segments.

See "Innovation and technology" on page 70.

2025 earnings [A]

Income/(loss) for the period was driven by the same factors as Adjusted Earnings and includes Identified items, which in 2025 amounted to a net loss of \$104 million.

The Adjusted Earnings loss position decreased by \$98 million compared with 2024. This reflected favourable tax movements (\$825 million), partly offset by unfavourable net interest movements (\$440 million) and currency exchange rate effects (\$191 million).



Photo: CEO quarterly all-staff engagement, Krakow, November 2025.

[A] All earnings amounts are shown post-tax unless otherwise stated.

Key metrics [B]

	\$ million, except where indicated		
	2025	2024	2023
Income/(loss) for the period	(1,974)	(2,992)	(2,944)
Identified items [B]	(104)	(1,024)	(69)
Adjusted Earnings* [B] [C]	(1,870)	(1,968)	(2,875)
Adjusted EBITDA* [C]	(1,193)	(675)	(1,164)
Cash flow from operating activities	(3,123)	(1,882)	(832)

[B] See Note 7 to the "Consolidated Financial Statements" on pages 259-267.
[C] Adjusted Earnings and Adjusted EBITDA are presented on a current cost of supplies basis.
* Non-GAAP measure. See page 430.

Prior year earnings [A]

Income/(loss) for the period was driven by the same factors as Adjusted Earnings and includes Identified items, which in 2024 amounted to a net loss of \$1,024 million.

The Adjusted Earnings loss position decreased by \$907 million compared with 2023. This reflected favourable tax movements (\$396 million), net interest movements (\$280 million) and currency exchange rate effects (\$192 million).

Identified items in 2024 included reclassifications, from equity to profit and loss, of cumulative currency translation differences principally related to funding structure changes, resulting in unfavourable movements of \$1,122 million.

Cash flow from operating activities

Cash flow from operating activities for the full year 2025 was primarily driven by working capital outflows of \$1,505 million, which included a reduction in joint-venture deposits, as well as Adjusted EBITDA and tax payments of \$425 million.

Self-insurance

Shell, like other major oil and gas companies, self-insures most of its exposures to hazard risks. Our Group insurance companies are wholly owned subsidiaries. They provide insurance coverage to our subsidiaries and entities in which we have an interest, including those that are not controlled by Shell.

We continually assess the safety performance of our operations and make risk mitigation recommendations, where relevant, to keep the risk of an accident as low as possible. As regulated and licensed companies, our Group insurance companies are adequately capitalised. They may transfer risks to third-party insurers where economical, effective and relevant.

See page 132 of "Risk factors".



Innovation and technology

Innovation

Shell has a long history in technology and innovation. Our global network of research and development (R&D) centres seeks to deliver innovative, cost-competitive solutions that meet global energy demands while reducing emissions.

We collaborate closely with our customers, suppliers and partners, as well as with many universities and research institutes. We also work with some of the world's leading technology companies to deploy digital solutions at scale across our businesses.

Technology helps to improve our efficiency, safety and competitiveness. By applying our technical and digital capabilities, we can also contribute to building the low-carbon energy system of the future.

In 2025, we invested \$1,170 million in R&D. We combine our expertise in R&D with digital solutions, often powered by AI, to help accelerate innovation and effectively scale up.

Shell's Technology organisation and our businesses work together to determine the content, scope and budget for developing new technology that supports our activities. This includes partnering with start-ups and small- to medium-sized enterprises that are in the early stages of developing new technologies through our Shell Ventures and Shell GameChanger programmes.

New technology is developed using a maturation process, to systematically mitigate technical and commercial risks, while staying aligned with Shell's strategic ambitions and deployment commitments.

See page 133 of "Risk factors".

Intellectual property

At Shell, we have a wide-ranging intellectual property (IP) portfolio which includes patents, trademarks, know-how, trade secrets and copyrights. The distinctive Shell Pecten, a trademark in use since the early 20th century, and trademarks where the word Shell appears, help raise the profile of our Shell brand globally. We protect and defend our IP and we respect the valid IP rights of others. At December 31, 2025, we held 8,087 patents. This includes granted patents and pending patent applications.

Shell holds trademarks globally, even in countries where we no longer operate. For instance, in 2025, we renewed the trademark registration for "Midel" in Russia, through the renewal of the international trademark registration with the World Intellectual Property Organization, by paying the official fee of \$2,604 for all countries covered, of which \$120 was for Russia.

Information technology (IT) and cyber security

Digitalisation is a key success factor in delivering Shell's strategy. We are transforming our IT systems to support our evolving portfolio of businesses. We invest in new technologies, such as AI and quantum computing, enhancing our IT capabilities to improve the experience of our customers and make Shell a more efficient organisation. Digital technologies are increasing the effectiveness and efficiency of our processes by collecting quality data, turning this data into insights and insights into actions that improve the performance of our assets.

The growing dependence on IT and rising data volumes introduce risks. A breach in IT systems or data loss could significantly impact Shell and its supply chain, leading to productivity disruptions, loss of confidential information, regulatory penalties and potential reputational harm. Additionally, sanctions, including orders to delete data and regulatory fines, might be imposed on Shell if authorities find Shell failed to meet its obligations in relation to cyber security or personal data protection.

In 2025, we continued to implement a comprehensive cyber security programme as part of our cyber defence strategy. This was done in adherence to Information and Digital Technology (IDT) requirements based on the Shell Performance Framework (SPF). Our Information and Digital Technology Standard sets out a structured approach to identify, assess and mitigate IT and cyber security risks. Following the approval of the IDT requirements, we refreshed our Information Risk Management capabilities and streamlined the organisational structure to enhance the formal Chief Information Security Officer (CISO) role, with support from the Executive Committee. This included integrating the cyber defence teams and other decentralised cyber security functions into the central Cyber and Information Security Office organisation. These changes came into effect on March 1, 2025.

Our global cyber and information security teams are staffed with cyber security professionals that monitor, assure and help defend our global IT and data landscape. As our employees and contractors play a role in protecting our IT systems, we provide them with targeted training on data protection and regulatory compliance, and regularly run cyber security awareness campaigns, including simulations on how to respond to cyberattacks. We evaluate emerging digital technologies to understand the risks, their impact and necessary remediation of this impact. Additionally, Shell works to monitor and respond in real time to cyber security incidents as they happen.

Cyber and information security risk management

Our cyber security capabilities are embedded into our IT systems, and our IT and data are protected by various detective and protective technologies and controls. A structured approach to identify, assess and mitigate the IT and cyber security risks is built into our support processes and is benchmarked to external best practices. We continuously track cyberattacks, threat intelligence, cyber legislations and vulnerabilities relevant to our IT landscape, and have a structured incident management and escalation process in place.

The security of IT services, where operated by external IT companies, is managed through a risk-based approach, including information and cyber security assessments, contractual clauses and additionally through supplier assurance reports issued by independent third parties for critical IT services. Shell collaborates periodically with service providers and supplements these reports with internal benchmarking to assess our cyber security risk management practices against cyber security best practices and peer organisations. We enhance our cyber security capabilities and adopt a risk-based strategy for our cyber risk investment decisions by leveraging insights from assessments, adapting to changes in external risks, and incorporating the results of internal audits and control testing.

Shell employees and contract staff are required to complete mandatory training courses and participate in regular cyber threat awareness campaigns. The Think Secure Scorecard was introduced in 2024 across the organisation. It provides data insights into the cyber behaviour of Shell staff on an individual level, encouraging continuous learning about cyber threats and advocating personal accountability. Shell has robust governance processes to monitor key cyber and information security risks, provide risk assurance and encourage a corporate culture that prioritises security.

Our cyber security strategy is regularly reviewed and updated, as required, by our CISO and Shell's Information and Digital Technology leadership team, with oversight from the EC, the Audit and Risk Committee, and the Board. These reviews involve:

- consideration of changes to the external environment;
- strategic, operational and cultural risks;
- response to cyber security risks and implementation of further remedial actions as appropriate; and
- updates on the performance and benchmarking of the Group's cyber defences.

The Cyber and Information Security Office function performs periodic reviews and targeted deep dives that help ensure cyber and information security risk posture remains aligned with our enterprise risk management and regulatory expectations. Shell has established processes to report cyber security and data privacy incidents to relevant authorities as required by applicable regulatory requirements. In 2025, there were no cyber or data privacy incidents that had a material impact on Shell's business strategy, operations or financial condition.

The Cyber and Information Security Office leadership team involved in monitoring and managing our cyber security and information risk management processes has significant relevant experience. Effective April 1, 2025, with the departure of Shell's previous CISO, a new CISO was appointed. The CISO leads the cyber and information security function and is also responsible for global end-user and enterprise IT strategy, delivery and operations. Together with his leadership team, he helps ensure secure, scalable and resilient digital infrastructure to support Shell's businesses and transformation functions. With more than 26 years of experience in global IT leadership, including leadership roles at IBM, Cables & Wireless and Serco, he brings deep expertise in strategic change, innovation and operational excellence. At Shell, he has held senior IT positions across all major businesses and functions. Furthermore, he is active in cyber security industry trade groups. The CISO is supported by a leadership with extensive and significant cumulative experience spanning decades, possessing multiple relevant certifications including but not limited to Certified Information Systems Security Professional (CISSP), Certified Information Systems Auditor (CISA), Certified in Risk and Information System Control (CRISC) and Certified in the Governance of Enterprise IT (CGEIT). The leadership team also actively participates in various industry forums.



Transforming gas production in Norway

At Ormen Lange, the Phase 3 sub-sea compression project was completed and delivered first gas in June 2025. The project represents the world's deepest sub-sea compression system and is expected to increase the field recovery rate from 75% to 85%, unlocking an additional 30–50 billion cubic metres of gas to supply Europe's energy needs. The new compression system is connected to the Norwegian grid, which is largely supplied by renewable power, and operates remotely without an offshore platform, reducing human risk and the impact on the surrounding environment.

Intel certifies Shell cooling fluids for data centres

In 2025, Shell Lubricants' immersion cooling fluids became the first to earn Intel Data Center Certification for Immersion Cooling, with confirmed compatibility with 4th and 5th Gen Intel Xeon processors. The certification follows two years of rigorous testing, which demonstrated that processors remain as reliable in Shell's immersion cooling fluids as in traditional air-cooled systems.

Pearl GTL in Qatar recognised for innovation

Pearl GTL in Qatar, the world's largest gas-to-liquids plant, has embraced smart technologies and artificial intelligence (AI) to enhance safety, efficiency and sustainability. This innovation was recognised by the World Economic Forum's Global Lighthouse Network in September 2025. The plant employs machine-vision systems to detect hazards in real time and alert supervisors, helping prevent safety incidents. AI also monitors equipment health, reducing manual inspections and enabling early intervention.

Photo: Ormen Lange, Norway, 2025.



Less emissions

We are committed to playing our part in helping to decarbonise the global energy system. We have a target to become a net-zero emissions energy business by 2050.

In 2025, we continued to make progress against our climate-related targets and ambition. At the end of 2025, we had reduced our Scope 1 and 2 operational emissions by 36%, and the net carbon intensity (NCI) of our energy products by 9% from our 2016 baseline. We had also achieved our target of eliminating routine flaring from our upstream operations by 2025 and continued to maintain methane emissions intensity for our operated oil and gas assets below 0.2%.

Additionally, we have delivered an 18% reduction to date as part of our ambition to reduce customer emissions from the use of our oil products (Scope 3, Category 11) by 15-20% by 2030 compared with 2021.

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Shell and the energy transition

The world needs a balanced energy transition, one that maintains secure energy supplies, while accelerating the transition to affordable low-carbon solutions. We believe our strategy supports a balanced transition by providing the oil and gas people need today, while helping to build the energy system of the future.

We recognise that the scale of the energy transition requires fundamental change in both supply and demand. It will take supportive government policies, advances in technology and investments by companies across all parts of the economy to achieve this. We advocate policies, legislation and regulations in areas where we can best support the decarbonisation of our customers, reduce our own emissions and help accelerate the energy transition.

There remains significant uncertainty around the shape of the future energy system. As a result, we are developing a multi-energy portfolio that has the flexibility to respond to uncertainty and that we believe will allow us to remain a successful business with a target to become a net-zero emissions energy business by 2050.

It will take significant investment to maintain the stable and secure supplies of energy that the world needs. Shell's future investments are guided by market signals and strategic signposts, ensuring decisions align with our profitability and resilience objectives under both cost and carbon considerations. Our strategy is to deliver more value with less emissions by:

- Growing our integrated gas and LNG business;
- Keeping liquids production stable; and
- Transforming Downstream, Renewables and Energy Solutions.

Gas, including LNG, is a stabilising force in energy systems because it is versatile, flexible and reliable. Gas is versatile because it can be used in power generation, industry, heating and transport. It is also flexible and reliable because it is simple to deploy and can be shipped, as LNG, to where it is needed to meet changing demand. Gas is a lower-carbon alternative to coal in power generation and industry, and to oil in transport [A]. Gas can balance renewable energy to provide stability for national grids. We believe that supplying LNG will be the biggest contribution we will make through the next decade of the energy transition as we help to build the energy system of the future.

[A] According to the International Energy Agency, globally, on average, the life-cycle GHG emissions intensity of electricity produced from LNG is around 40% lower than for electricity produced from coal. "Assessing Emissions from LNG Supply and Abatement Options" report from the IEA, June 19, 2025.

The role of oil and gas will be critical to the energy system for decades to come. We are working to cut the emissions from our oil and gas production and processing, prioritising cost- and carbon-competitive oil and gas. We aim to sustain liquids production and will focus on basins where we have a competitive advantage.

We are focused on enhancing value from our Downstream, Renewables and Energy solutions businesses. We are repositioning Chemicals, power and low-carbon options (including carbon capture and storage (CCS), hydrogen and low-carbon fuels) to unlock greater value and support our climate-related targets and ambition. We aim to lead in the energy transition where we have competitive strengths, see strong customer demand and identify clear regulatory support from governments.

Energy Transition Strategy 2024

In March 2024, we published our Energy Transition Strategy 2024 (ETS24), which shareholders approved at the AGM. We updated our plans, covering all our businesses, to reduce emissions from our operations and help our customers to decarbonise, focusing on:

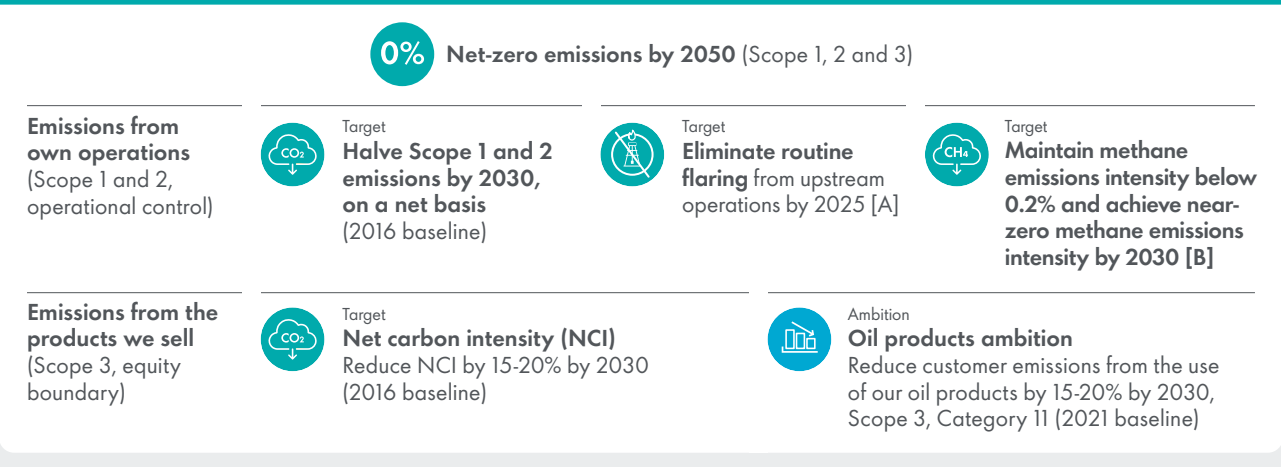
- Growing our world-leading LNG business with lower carbon intensity operations by using CCS and renewable power, and reducing methane emissions;
- Cutting emissions from oil and gas production in our Upstream business, implementing carbon management plans and working to reduce carbon emissions from our assets, by looking at ways to electrify our offshore oil facilities, including using wind and solar power to reduce operational emissions; and
- Offering low-carbon solutions from our Downstream, Renewables and Energy Solutions businesses such as biofuels and electric vehicle charging, developing our integrated power positions and working to unlock the potential of CCS to reduce emissions where there are few low-carbon alternatives.

We set targets to reduce the carbon intensity of the energy products we sell, measured by using our net carbon intensity (NCI) metric. We believe these targets are aligned with a 1.5°C pathway derived from scenarios developed for the Intergovernmental Panel on Climate Change's (IPCC's) Sixth Assessment Report (AR6). For more information see "Setting targets for NCI" on page 96.

The progress we have made towards our climate-related targets and ambition is set out on page 87.

See "Our strategy" on pages 9-11.

Climate-related targets and ambition

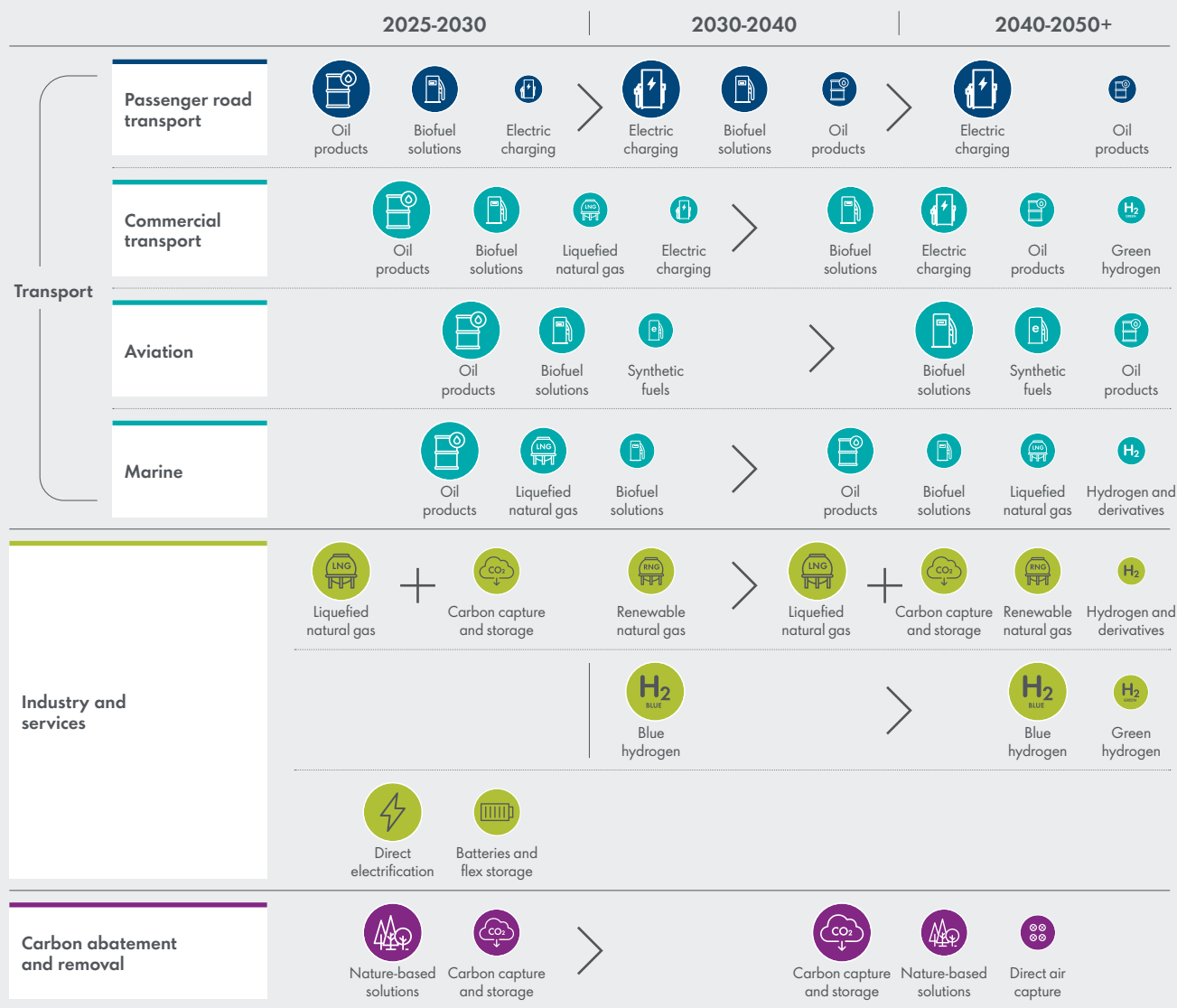


[A] This target was subject to the completion of the sale of The Shell Petroleum Development Company of Nigeria Limited (SPDC). We ceased routine flaring of associated gas in January 2025, achieving our target independent of the sale of SPDC to Renaissance. As detailed elsewhere in this report, on March 13, 2025, Shell completed the sale of SPDC to Renaissance.

[B] Methane intensity is measured and calculated separately for oil and gas assets with marketed gas (gas, LNG and GTL available for sale) and assets without marketed gas (oil and gas assets where gas is reinjected).

Focused decarbonisation pathways

We have identified pathways to net zero for our two biggest customer sectors, transport and industry. These two sectors make up more than 70% of total global final energy demand and more than 55% of global carbon emissions today [A]. Our pathways are based on sectors where we believe we have the competitive advantage to provide our customers with the affordable products they need through the transition.



Note: The order from left to right and the size of the circles in the graphic above indicate their likely relative prominence within that section of the pathway. Significant uncertainty remains on the shape of these future pathways.

Leading to our strategic decarbonisation areas for this decade

Electric vehicle
charging

Biofuels
infrastructure

Integrated power
positions

CO₂ capture and
removal value chains

Enabled by our strengths and competitive advantages

Trading capabilities
and infrastructure network

Technology
and innovation

Policy and
advocacy

[A] We include services in the "Industry" sector. Services are included under the "Buildings" sector in the IEA end use definition.

[B] Blue hydrogen is generated from hydrocarbon feedstocks with CO₂ capture and storage. Green hydrogen production uses renewable electricity to electrolyse water into H₂ and O₂.

Climate-related risks and opportunities identified by Shell over the short, medium and long term

We are continually enhancing our approach to assessing and managing the risks and opportunities resulting from climate change. This includes considering different time horizons and their relevance to risk identification and business planning. We actively monitor societal developments, such as regulation-driven carbon pricing mechanisms and customer-driven preferences for products. We incorporate these developments, where relevant, into potential scenarios which provide insights into how the energy transition may unfold in the medium and long term. These insights and those from various external scenarios (such as those prepared for the IPCC's AR6) help guide how we set our strategy, capital allocation and climate-related targets and ambition.

The process for identifying and assessing climate-related risks is set out in "Risk management" on page 125. The impact and likelihood assessment described on page 125 helps us to prioritise climate-related risks and determine their relative materiality, based on a comprehensive picture of significant risks to any relevant business objectives. We consider climate-related risks from a strategic, operational, conduct and culture perspective to help us maintain a comprehensive view of the different types of climate risks we face and the different time horizons in which they may affect us. Monitoring and reviewing risks is a key risk management process. The Executive Committee, the Board and Board committees review climate-related risks and their impact on the Group, as appropriate. This allows management to take a holistic view and optimise risk mitigation responses, to ensure that climate-related risk responses are properly integrated into the relevant activities.

Shell has identified climate change and the energy transition as a material risk. The risk could potentially result in changes to the demand for our products, supply chains and markets; further changes to the regulatory environment in which we operate; and increased litigation (see Note 32 to the Consolidated Financial Statements "Legal proceedings and other contingencies" on page 303).

The risk is composed of a combination of complex and interrelated elements that affect Shell's value chain and our asset, product and business portfolio. The risk landscape is evolving rapidly. To achieve our climate-related targets and ambition, active holistic management of all climate-related risk components is important. The composite risk is broken down into the following sub-components:

- commercial risk;
- societal risk (including litigation risk);
- regulatory risk; and
- physical risk.

We are working to mitigate our identified climate-related risks and deliver more value with less emissions by focusing on performance, discipline and simplification. We believe we are positioning ourselves to achieve our financial targets and climate-related targets and ambition by:

- reducing the GHG emissions from our operations (Scope 1 and 2) by improving our energy efficiency, deploying renewable electricity and reducing methane emissions in our assets and projects;
- growing our LNG business while decarbonising our portfolio by prioritising lower carbon intensity assets and investing in innovative decarbonisation pathways, including abatement projects to reduce CO₂ and methane emissions;

- managing our Integrated Gas and Upstream portfolio to support a balanced energy transition by cutting emissions from oil and gas production; and
- transforming our Downstream and Renewables and Energy Solutions business, supported by our global trading and supply capabilities, to offer low-carbon energy solutions.

We adapt our assets and activities as necessary to enhance our resilience to physical risks, whether or not related to climate change. Many of these adaptations are based on our Safety, Environment and Asset Management (SEAM) Standards and practices.

See page 78 for more details of physical risks.

Our approach to climate change emphasises the need to work collaboratively. We therefore work closely with customers, other companies and sectors to help decarbonise the global energy system.

We engage with governments on their climate policies to advocate policies that help establish regulatory frameworks to enable Shell to invest profitably in products and services that will help deliver a balanced energy transition. We are a founding member of the Oil and Gas Climate Initiative (OGCI), a group of 12 national and international energy companies supporting these goals through collective action.

We are signed up to the Oil & Gas Decarbonization Charter (OGDC), in which companies have pledged to achieve near-zero methane emissions intensity by 2030, zero routine flaring by no later than 2030 and commit to halving Scope 1 and 2 emissions by or before 2050. In April 2024, we became the first official partner to the World Bank Global Flaring and Methane Reduction Fund Partnership, which we committed to at the 28th Conference of the Parties (COP28) in 2023. We are a founding signatory of the Oil and Gas Methane Partnership (OGMP) 2.0 reporting framework. Shell achieved the OGMP 2.0 Gold Standard in methane emissions reporting in 2023 and 2024.

As a leading global energy business, Shell seeks to identify opportunities in the energy transition. These risks and opportunities are described below. Climate-related risks are also summarised in the "Risk management and risk factors" section on pages 129-130.

Time horizons: Short, medium and long

Due to the inherent uncertainty and pervasive risks across our strategy and business model, we monitor climate-related risks and opportunities across multiple time horizons.

- Short term (up to three years): we develop a detailed Operating Plan to manage performance and expectations on a three-year cycle. The Operating Plan is updated every year and incorporates decarbonisation measures required to meet our short-term targets.
- Medium term (generally three to 10 years): we develop an outlook with our continued focus on the customer, the investments and portfolio shifts we believe are required in the medium term to shape Shell's portfolio.
- Long term (generally beyond 10 years): the level of uncertainty increases over longer time horizons. Our portfolio and product mix are expected to evolve over time with changing customer demand.

Transition risks

Description	CR1 Climate-related commercial risks - The transition to a low-carbon economy may lead to lower sales volumes and/or margins due to a general reduction or elimination of demand for oil and gas products, possibly resulting in underutilised or stranded oil and gas assets, and a failure to secure new opportunities. - Changing preferences of investors and financial institutions could reduce access to and increase the cost of capital.
Relevant time horizon	medium and long
Potential material impacts	Lower demand and margins for oil and gas products - Changing customer sentiment in some markets, favouring the use of renewable and sustainable energy products, may reduce demand for our oil and gas products. An excess of fossil fuel supply over demand could result in reduced fossil fuel prices. This could result in lower earnings in the future, cancelled projects and potential impairment of certain assets. Changing preferences of investors and financial institutions - Certain investors have decided to divest their investments in fossil fuel companies. If this were to increase significantly, it could have a material adverse effect on the price of our securities and our ability to access capital markets. Some investors and financial institutions have been aligning their portfolios to low-carbon opportunities, driven by both regulatory and broader stakeholder pressures. - A failure to decarbonise our business portfolios in line with investor and lender expectations could have a material adverse effect on our ability to access financing for certain types of projects. This could also adversely affect our partners' ability to finance their portion of costs, either through equity or debt. - Sensitivity analysis of a 1% shift in Shell's weighted average cost of capital (WACC) on asset carrying values is presented in the section "Carbon pricing and discount rate sensitivities" on page 84. Remaining in step with the pace and extent of the energy transition - The energy transition provides us with significant opportunities, as described in "Climate-related opportunities" (CO1) below. If we fail to stay in step with customers' and other stakeholders' demand for low-carbon products, this could adversely affect our reputation and future earnings. If we move much faster than society, we risk investing in technologies, markets or low-carbon products for which there may be insufficient demand. If we are slower than society, or if low-carbon technology advances faster than we expect, customers may prefer a different supplier. This would reduce demand for our products and adversely affect our reputation and materially affect our financial results. - Low-carbon technology and innovation are essential to our efforts to help meet the world's energy demands competitively. If we are unable to develop the right technology and products in a timely and cost-effective manner, there could be an adverse effect on our future earnings. The operating margins for our low-carbon products and services [A] have been, and could continue to be, lower than the margins we have experienced historically in our oil and gas operations.
Description	CR2 Climate-related societal risks (including litigation) Societal expectations around energy security and affordability, and mitigating climate change, continue to shift, creating uncertainty, with a potential impact on Shell's licence to operate, reputation, brand and competitive position. This is likely to include litigation.
Relevant time horizon	short, medium and long
Potential material impacts	Decline in reputation, brand and licence to operate - Societal expectations around energy security, affordability and mitigating climate change continue to shift with uncertain implications for businesses with regard to mix and quality of products, safety and minimising damage to the environment. The role of the oil and gas sector in the context of climate change and the energy transition has been, and continues to be, an area of focus and public debate. This has negatively affected, and in the future could negatively affect, our licence to operate, our brand, reputation and competitive position; and could reduce consumer demand for our products, harm our ability to secure new resources and contracts, and restrict our ability to access capital markets or attract employees. Deteriorating relationships with key stakeholders - Failure to decarbonise Shell's value chain in line with societal, governmental and investor expectations is a material risk to Shell's reputation as a responsible energy company. The impact of this risk includes shareholder divestment, greater regulatory scrutiny and potential asset closure resulting from public interest groups' protests. Litigation - There is an increasing risk to oil and gas companies from private (including non-governmental organisations) and governmental lawsuits. If successful, these claims may have wide-ranging consequences, including forcing entities to hand over strategic autonomy in part to regulators, divesting from hydrocarbon technologies, denying entities regulatory approvals and/or requiring payment of fines or penalties or large compensation packages to plaintiffs. - In some countries, governments, regulators, organisations and individuals have filed lawsuits of a wide variety, including seeking to hold oil and gas companies liable for costs associated with climate change, or seeking court-ordered reductions in emissions, challenging the regulatory approvals and operating licences, or challenging energy transition strategies and plans. While we believe these lawsuits to be without merit, losing could have a material adverse effect on our earnings, cash flows and financial condition. - In the Netherlands, a group of environmental NGOs and individual claimants (referred to herein as "Milieudefensie") filed an appeal on February 11, 2025 with the Dutch Supreme Court against the Court of Appeal judgment of November 12, 2024, which overturned a lower court finding that Shell had an obligation to reduce certain aggregate annual volumes of CO₂ emissions by 2030. - We have also been subjected to climate activism which has caused disruptions to our operations, and such disruptions could happen again in the future.

[A] Electric vehicle charging services, renewable power generation, nature-based solutions, green hydrogen, CCS. We define low-carbon energy products as those that have an average carbon intensity that is lower than that of conventional hydrocarbon products, assessed on a life-cycle basis.

Transition risks continued

Description	CR3 Climate-related regulatory risks The transition to a low-carbon economy continues to increase compliance costs for our assets and products, and may restrict the use of hydrocarbons. The lack of net-zero-aligned global and national policies and frameworks, and a fluid regulatory environment, increase the uncertainty around this risk.
Relevant time horizon	short, medium and long
Potential material impacts	Increased compliance costs - Some governments have introduced carbon pricing mechanisms, which we believe can be an effective way to reduce GHG emissions across the economy at the lowest overall cost to society. - Shell's cost of compliance with the Emissions Trading Scheme (ETS) and related schemes was around \$398 million in 2025, as recognised in Shell's Consolidated Statement of Income for 2025. A further \$4,733 million of costs in respect of emissions schemes and related environmental programmes were incurred in respect of biofuels (\$4,203 million) and renewable power (\$530 million) programmes (see Note 5 to the "Consolidated Financial Statements" on pages 256-257). - Shell's annual carbon cost exposure (including ETS and related schemes) is expected to rise as carbon pricing expands globally and average prices increase, with the forecast annual cost exposure in 2026 estimated to be around \$1 billion and around \$4 billion in 2035. This estimate is based on a forecast of Shell's equity share of emissions from operated and non-operated assets, and real-term carbon cost estimates using the mid-price scenario (see Note 4 to the "Consolidated Financial Statements" on pages 244-255 for more information) [A]. This exposure also takes into account the estimated impact of available CO₂ free allowances as relevant to assets based on their location [B]. Restrictions on use of hydrocarbons - Governments may introduce further restrictions on hydrocarbon exploration and production and impose stricter standards for decommissioning, which could affect timing and costs. Failure to replace proved reserves could result in an accelerated decrease of future production, which could have a material adverse effect on our earnings, cash flows and financial condition. Lack of net-zero-aligned global and national policies and frameworks - Divergence in regulatory direction has created, and continues to create, uncertainty and complexity for multinational companies operating globally. The renewed focus on the competitive agenda in the EU aims to simplify current and incoming climate regulations and disclosure requirements, with the USA moving towards deregulation at the federal level, even as some states adopt stricter rules. - The lack of net-zero-aligned global and national policies and frameworks increases the uncertainty around how carbon pricing and other regulatory mechanisms will be implemented in the future. This makes it harder to determine appropriate assumptions for financial planning and investment decisions, which could impair our ability to assess the robustness of our plans and opportunities. Rapid changes in government climate and energy-transition-related policies and regulations could also lead to impairments of our existing oil and gas assets. - The lack of consistent government policy needed to provide a conducive regulatory environment for low-carbon products and solutions could make it more challenging to take investment decisions on projects that we and society need to reach our respective decarbonisation goals as policy is critical in creating sustained demand for new low-carbon solutions in many sectors. Similarly, climate policy approaches that hamper or constrain market efficiency and competition increase costs and make projects less attractive, challenging our ability to deliver our strategy.

[A] Carbon cost estimates that include inflation; usually a yearly 2% inflation is applied.

[B] Free allowances are amounts of CO₂ an asset is allowed to emit without paying the emissions trading scheme price/tax.

Physical risks

Description	CR4 Climate-related physical risks The potential physical effects of changing climatic conditions could adversely affect our assets, operations, supply chains, employees and markets.
Relevant time horizon	short, medium and long
Potential material impacts	Types of physical risk The impact of physical risks comes from both acute and chronic climate hazards. Acute hazards, such as flooding and droughts, wildfires and more severe tropical storms, and chronic hazards, such as rising temperatures and rising sea levels, could potentially impact some of our facilities, operations and supply chains. The frequency of these hazards and impacts is expected to increase in certain locations. Extreme weather events, whether or not related to climate change, could have a negative impact on our earnings, cash flows and financial condition. Mitigation of physical risks, whether or not related to climate change, is considered and embedded in the design and construction of our projects, and/or operation of our assets, to help minimise the risk of adverse incidents to our employees and contractors, the communities where we operate and our equipment. Shell's assessment - In 2023, we carried out a detailed review to assess the impact of a range of changing climatic conditions, including projected changes in temperature, precipitation, wind and sea levels, across segments and geographies for our significant assets. We used IPCC climate modelling data covering three exploratory climate scenarios (RCP2.6, RCP4.5 and RCP8.5 [A]) across the time horizons 2025, 2030 and 2050. These scenarios were selected to ensure a broad range of risks and uncertainties were assessed. There have been no changes to the climate modelling data that would require a full update of the 2023 assessment. An annual process has been established to review the 2023 work, reconfirm the significant assets, verify that there are no changes to the risk profile of our significant assets and account for portfolio changes. - In the short to medium term, the risks identified were found to be related to factors that Shell is already aware of (whether or not related to climate change) and that the assets are actively managing to mitigate, e.g. hurricane impacts on the US Gulf Coast, rising air temperatures in the Middle East and water scarcity in Europe and Asia. As an example, in recent years the Rhine river in Europe has seen historic lows during the summer months, leading to challenges in the use of barges for transportation of our products. Dredging of harbours and investment in shallower-draft barges have helped to mitigate the risk. - In the long term, the results of the exercise indicated that, while we have evaluated against current climate modelling projections and our current asset portfolio, by 2050 the frequency and severity of the climate hazards may differ from current projections. The level of predictability is such that the need for investment in climate adaptation measures at the assets is not immediate and the results mean the assets are in a position to monitor their condition and determine whether there is any need for adaptation action, e.g. the impact of potential water scarcity on various assets. - Our testing to assess the potential impact of climate-related changes on our significant assets covers over 70% of the carrying value of our physical assets as at December 31, 2024. Over 12% (based on the carrying value) of physical assets tested are considered to be exposed to climate-related physical risks in the short to medium term, which the assets are already actively managing to mitigate. In addition, we have reviewed significant acquisitions made and projects reaching FID since 2023, none of which were found to have significant climate-related physical risks in the short to medium term. - Our business plan reflects the impact of mitigating actions in the short to medium term for the assets assessed. We will continue to monitor and assess the future exposure of our assets in the longer term to changing climatic conditions to establish the need for any further adaptation actions and related metrics. - The impact of physical climate change on our operations is unlikely to be limited to the boundaries of our assets. For example, the downstream transportation and distribution of our products from our own operations could potentially be exposed to climate-related hazards that ultimately impact our operations. The overall impact, including how supply chains, resource availability and markets may be affected, also needs to be considered for a holistic assessment of this risk. Our assets manage this risk as part of broad risk and threat management processes as required by our SEAM Standards, which are part of the wider Shell Performance Framework.

[A] Representative Concentration Pathway (RCP) refers to the GHG concentration (not emissions) trajectory adopted by the IPCC. The pathways describe different climate change scenarios, all of which are considered possible depending on the amount of GHG emitted in the years to come.

Opportunities

Description	CO1 Climate-related opportunities ◦ The transition to a low-carbon economy also brings significant opportunities for us to benefit from changing customer demands, given our position as a leading global energy provider.
Relevant time horizon	short, medium and long
Potential material impacts	As the global energy mix changes, our current infrastructure, know-how and global footprint put us in an ideal position to service the changing energy demands of the market. Our global customer reach, our use of technology and innovation to develop the business models and fuels of the future and the strength of our trading capabilities, coupled with our own production, will help us deliver affordable and low-carbon energy products and solutions for our customers. Our R&D activities are an important contributor to achieving our climate-related targets and ambition. We aim to be the investment case and partner of choice through the energy transition. As we work to deliver more value with less emissions we are focusing on: LNG ◦ Demand for LNG is expected to grow. Today, we are the world's leading publicly listed supplier of LNG, with around 44 million tonnes of equity capacity. Our Integrated Gas portfolio is the largest amongst peers, servicing nearly a fifth of global LNG demand. We believe that supplying LNG will be the biggest contribution we will make through the next decade of the energy transition as we help to build the energy system of the future. In the future, the production of gas could be decarbonised through carbon capture storage, biogas and synthetic gas. Gas, including LNG, is a stabilising force in energy systems because it is versatile, flexible and reliable. Gas is versatile because it can be used in power generation, industry, heating and transport. It is also flexible and reliable because it is simple to deploy and can be shipped, as LNG, to where it is needed to meet changing demand. Gas is a lower-carbon alternative to coal in power generation and industry, and to oil in transport. According to the IEA, globally, on average the life-cycle GHG emissions intensity of electricity produced from LNG is around 40% lower than electricity produced from coal [A]. LNG is the lowest-carbon marine fuel available at scale today and offers significant GHG emissions reductions compared with conventional fuels. Gas can balance renewable energy to provide stability for national grids. Shell has developed the world's largest LNG fuelling network of ports and bunker vessels on key trading routes, enabling more customers to choose LNG. Beyond our own production, we expect to continue to add scale and flexibility to our portfolio by buying LNG from others. Our integrated model is at the heart of LNG value creation, with our business spanning every stage of the LNG journey. Biofuels ◦ We invest in biofuels where we see growing customer demand and where we can use the strength of our supply and trading positions. Aviation and shipping remain some of the slower-to-decarbonise sectors and we expect that they will require low-carbon solutions, such as biofuels, at scale in the future. Shell is already one of the world's largest energy traders and blenders of biofuels, selling significantly more low-carbon fuels than we produce, using the strength of our trading business to expand sales beyond our production volumes. Through our Raizen joint venture in Brazil we are already the largest producer of second-generation ethanol and the leading sugarcane ethanol producer globally. To support growing demand for biofuels this decade, we are developing more second-generation technologies. We are also developing technologies and feedstocks that aim to allow continued and sustainable growth in biofuels, while minimising impacts on the environment and food supplies. Integrated power ◦ Renewable power is expected to be critical for helping our commercial customers decarbonise, and we will continue to grow our integrated power business. We are making disciplined choices to create value from our portfolio, stepping back from activities that do not fit our strategy or generate enough return. We are focusing on selling power, including renewable power, to business customers. We are using and will continue to use the strength of our trading and optimisation capabilities to meet the growing need for flexible power storage solutions, such as batteries. We already have a significant presence in battery and storage through our third-party toll arrangements, ventures programme and investments in R&D. We are also using renewable power to decarbonise our own operations. Over time, we expect to use our renewable power capacity to produce low-carbon molecules, such as hydrogen. Electric vehicle charging ◦ We continue to invest in public electric vehicle charging in key markets such as China, Singapore, and Europe, where we see the greatest value emerging from growing customer demand and the competitive advantage provided by our global network of service stations. Our network is supported by our established convenience retail offering, which allows us to offer our customers coffee, food and other convenience items and services while they charge their cars. Our investment decisions are guided by factors such as network accessibility, market readiness, technical progress, and the policy landscape. Carbon capture and storage ◦ We are developing technologies related to carbon capture and storage (CCS) and carbon removals, which are necessary to reduce emissions where there are few low-carbon alternatives. For the rest of this decade, we expect to direct most of our investments in CCS towards decarbonising our own operations. We are also looking to turn this into a profitable business for Shell by helping other companies decarbonise their operations in the future. However, in many countries, CCS still lacks a clear business model. To address this challenge, Shell advocates policy mechanisms to enable CCS and supports industry partnerships dedicated to the growth of commercially viable CCS projects.

[A] "Assessing Emissions from LNG Supply and Abatement Options" report from the IEA, June 19, 2025.

Impact of climate-related risks and opportunities on Shell's businesses, strategy and financial planning ¹

The transformation of the energy system to net-zero emissions will require simultaneous action in three areas:

- an unprecedented improvement in the efficiency with which energy is used;
- a sharp reduction in the carbon intensity of the energy mix; and
- the mitigation of residual emissions through the use of technology and natural sinks.

While it is difficult to predict the exact combination of actions that will deliver the net-zero goal, scenarios help us to consider the variables, and the potential direction and pace of the transition needed. Scenarios are not intended to be predictions of likely future events or outcomes and, therefore, are not the basis for Shell's Operating Plans and financial statements.

We have been developing scenarios within Shell for almost 60 years, helping Shell leaders to explore ways forward and make better decisions. Shell scenarios are designed to stretch management's thinking when it comes to considering events that may be possible, even if remotely. Scenarios help management to consider options and make choices in times of uncertainty and transition as we grapple with tough energy and environmental issues. They are aligned to different energy transition pathways and help in decision-making by guiding the identification of a wide range of risks and opportunities.

Different socio-economic and technological parameters are used to construct these scenarios, such as:

- sectoral and regional energy demand;
- regulatory and geopolitical developments;
- future trajectory of oil consumption and demand for natural gas;
- renewable electricity demand and the pace of the electrification of the global energy system;
- supply of solar and wind energy;
- pace of uptake of electric vehicles;
- demand for biofuels;
- growth of the hydrogen economy;
- level of CCS available;
- deployment of low-carbon energy technologies; and
- global trade of oil and gas.

Management consideration of different climate change outcomes informs a range of areas, including, but not limited to, the setting of the long-term strategy, business planning, and investment and divestment decisions. The outcomes considered by management vary in relation to the extent and pace of the energy transition.

Carbon Management Framework (CMF)

Shell's CMF provides the structure, processes, and responsibilities to drive delivery of Shell's climate-related targets and ambition.

The CMF is designed to embed carbon considerations into core management processes so that Shell can help accelerate the energy transition profitably while meeting its GHG reduction commitments.

An important part of the CMF is the use of carbon budgets for Scope 1 and 2 emissions as input and guidance for the annual business plan process. Carbon budgets are allocated at a business level as appropriate to support the optimisation of the business plan based on carbon/value synergies and dilemmas, and inform portfolio choices. For the 2025 business plan cycle, our 2030 Scope 1 and 2 and NCI targets and oil products emissions ambition were translated into a budget and guidance for each business. Performance against Shell's targets and ambition is monitored and reviewed by the EC on a quarterly basis, facilitating corrective action if required.

Another important element of the CMF is the integration of GHG emissions in project evaluations. GHG requirements are embedded in Shell's Opportunity Realisation Standard with the aim of facilitating informed decision-making by identifying potential carbon/value synergies and dilemmas.

Greenhouse gas and energy management

Each Shell entity and Shell-operated venture is responsible for the development of its Greenhouse Gas (GHG) Emissions and Energy Management Plan. Plans are in place for all significant assets.

Our GHG and Energy Management process sets out Shell's requirements for GHG reduction opportunities and portfolio choices to meet our carbon budgets and achieve our climate-related targets. These requirements allocate accountabilities for GHG and energy management within businesses, assets and projects, including responsibility for analysing our emissions, identifying improvement opportunities and forecasting future performance. These requirements are applied to capital project delivery and through the asset-level annual business planning process, ensuring it is reflected in both opportunity realisation and strategic asset management planning.

A key aspect of the GHG and Energy Management process is the development of an energy efficiency and GHG reduction opportunity curve, economically assessed against the current and future costs of carbon. This information provides the basis for forecasts of absolute GHG emissions and associated intensities at the asset and project level. These forecasts are then aggregated to inform decisions on potential decarbonisation opportunities across our businesses.

The Shell Global Process Council for GHG and Energy Management, led by the Global Process Owner for GHG and including business and functional experts, meets regularly to evaluate opportunities for the ongoing improvement of processes, tools, communications and capabilities needed within the businesses to achieve our climate-related targets.

Impact on strategic planning

The application of scenario analysis informs our assessment of the impact of a wide range of risks and opportunities, including climate-change-related issues, on our strategy and business planning at the Group and business levels. At the Group level, the potential impacts of the energy transition on our business model are discussed and assessed by the Board and the EC as part of the annual business planning cycle. This assessment allows us to challenge accepted ways of thinking, identify material risks and opportunities, and identify key dilemmas and trade-offs.

Key financial and non-financial components of business planning

The Board approves our annual business plan. The plan contains operational and financial metrics, and its objective is to drive the delivery of our strategy.

Decarbonisation targets are key to our business planning process. Each business owner offers viable Scope 1, 2 and 3 reduction opportunities as part of this process, in line with the CMF, see "Our approach to sustainability" on page 104.

The business plan is underpinned by assumptions about internal and external parameters and includes:

- commodity prices;
- refining margins;
- production levels and product demand;
- exchange rates;
- future carbon costs;
- the schedules of capital investment programmes; and
- risks and opportunities that may have material impacts on free cash flow.

These assumptions are developed with input from our scenarios and internal estimates and outlooks. The level of uncertainty around these assumptions increases over longer time horizons.

Impact on business and financial planning

There is no single scenario that underpins Shell's business and financial planning. Our scenarios help develop our future oil and gas pricing outlooks. These outlooks take account of factors relating to the energy transition, such as potential changes in supply and demand (see details of scenario parameters above). The low-, mid- and high-pricing outlooks are prepared by a team of experts, reviewed by the EC and approved by the CEO and CFO. The mid-price outlook represents management's reasonable best estimate and is the basis for Shell's financial statements, Operating Plans and impairment testing.

Shell's Operating Plan reflects Shell's strategy. We will continue to update our Operating Plan, price outlooks and assumptions as we work to reduce emissions.

As described in "Climate-related risks and opportunities identified by Shell over the short, medium and long term" on page 75, the low-pricing outlooks could result in increased commercial, regulatory and societal risks. The prioritisation of these risks is described in "Risk management" on page 125. We use low-pricing outlooks as part of our resilience testing and resulting actions.

Our strategy and national net-zero commitments

In accordance with UK Listing Rule 6.6.12G, we have taken into account the extent to which country-level net-zero commitments have been considered in developing our energy transition plans.

Our strategy is to deliver more value with less emissions, and we have a target to become a net-zero emissions energy business by 2050. The pace of the energy transition will be heavily influenced by government policy, which will create a strong country and regional dimension in seeking to deliver the goals of the Paris Agreement. Our commitment is a global one and, as such, we look to deliver our strategy through a global lens.

We seek to translate our energy transition plans into specific targets and plans at a business segment level. We also seek to take capital deployment and portfolio decisions in the context of the integrated nature of our global operations. However, we continue to recognise the importance of engagement and collaboration in delivering the fundamental changes to the energy system that are required. This includes supporting and advocating for policies that aim to reduce carbon emissions and working with governments and other stakeholders in the development of policies that support the transition to a low-carbon energy system. As national transition plans develop, consideration will be given to the impact on our operations and the associated implications for our energy transition plans.

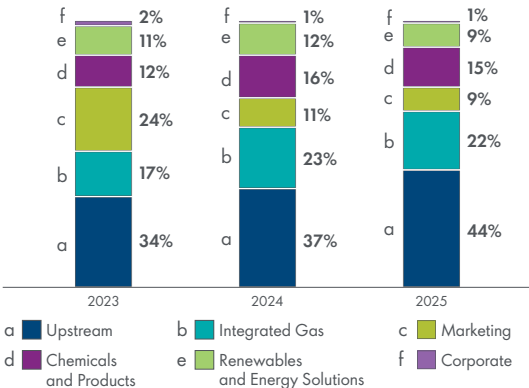
Resilience of Shell's strategy to different climate-related scenarios

Shell's financial strength and access to capital give us the ability to reshape our portfolio as the energy system transforms. They also allow us to withstand volatility in oil and gas markets.

As we implement our strategy, we continue to exercise focus and discipline to optimise our capital allocation and operational expenditure, balancing energy security and demand, as well as internal and external transition considerations and opportunities. We will make disciplined choices about where we can create the most value for our investors and customers through the energy transition.

Investing in the energy transition

Cash capital expenditure * evolution by segment



* Non-GAAP measure. See page 430.

Cash capital expenditure monitors investing activities on a cash basis, excluding items such as lease additions, which do not necessarily result in cash outflows in the period. The measure comprises the following items from the Consolidated Statement of Cash Flows: capital expenditure, investments in joint ventures and associates, and investments in equity securities. See Note 7 to the "Consolidated Financial Statements" on pages 259-267 for the reconciliation of cash capital expenditure.

Investing in the energy transition: Total cash capital expenditure

Total cash capital expenditure* of \$20.9 billion in 2025			
Non-energy products [A] \$2.0 billion		Low-carbon energy solutions [B] \$2.0 billion	
LNG, gas and power marketing and trading [C] \$4.6 billion		Oil, oil products and other [D] \$12.3 billion	

[A] Products for which usage does not cause Scope 3, Category 11 emissions: Lubricants, Chemicals, Convenience Retailing, Agriculture and Forestry, Construction and Road.

[B] Electric vehicle charging services, renewable power generation, nature-based solutions, green hydrogen, CCS. We define low-carbon energy products as those that have an average carbon intensity that is lower than that of conventional hydrocarbon products, assessed on a life-cycle basis.

[C] LNG Production and Trading, Gas and Power Trading, Energy Marketing.

[D] Upstream segment, GTL, Refining and Trading, Marketing fuel and hydrocarbon sales, Shell Ventures, Corporate segment.

Total cash capital expenditure was lower in 2025 compared with 2024 by \$0.2 billion, driven by:

- Non-energy products: \$0.2 billion lower spend due to the sale of Shell's Energy and Chemicals Park in Singapore in April 2025.
- Low-carbon energy solutions: \$0.4 billion lower spend due to the cessation of construction of the planned biofuels facility at Shell's Energy and Chemicals Park in Rotterdam in July 2024 and lower spend on e-Mobility and on CCUS.
- LNG, gas and power marketing and trading: \$0.4 billion lower spend compared with 2024 which included higher investments in Renewables and Energy Solutions.
- Oil, oil products and other: \$0.8 billion higher spend due to the acquisitions of additional interests in Upstream in deep-water Brazil, Gulf of America and in Nigeria, partly offset by lower spend in Upstream conventional assets, in Mobility and in GTL.

Cash capital expenditure* in 2026 is expected to be around \$12-14 billion for Integrated Gas and Upstream (\$14.0 billion in 2025), and around \$8 billion for Marketing, Chemicals and Products, and Renewables and Energy Solutions (\$6.9 billion in 2025).

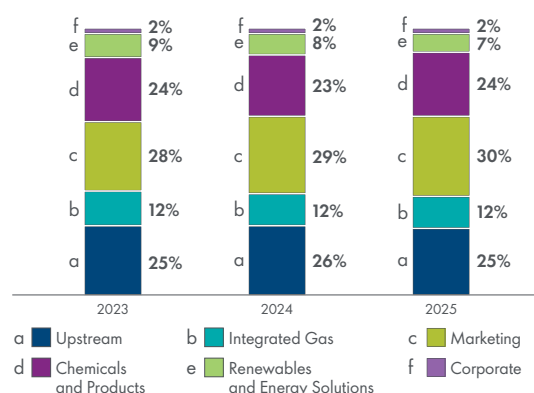
Energy transition: Total cash capital expenditure* by segment

		\$ billion					
Classification [1]	Segment	2025		2024		2023	
Non-energy products [A]	Marketing	0.6	2.0	0.6	2.2	0.9	2.3
	Chemicals and Products	1.4		1.6		1.4	
Low-carbon energy solutions [B]	Marketing	0.5	2.0	0.8	2.4	3.3	5.6
	Renewables and Energy Solutions	1.5		1.6		2.3	
LNG, gas and power marketing and trading [C]	Integrated Gas	4.3	4.6	4.2	5.0	3.7	4.0
	Renewables and Energy Solutions	0.3		0.8		0.3	
Oil, oil products and other [D]	Integrated Gas	0.4		0.6		0.5	
	Upstream	9.3		7.9		8.3	
	Marketing	0.7	12.3	1.0	11.5	1.6	12.5
	Chemicals and Products	1.7		1.8		1.6	
	Renewables and Energy Solutions	0.0		0.1		0.1	
	Corporate	0.1		0.1		0.4	
Total		20.9	20.9	21.1	21.1	24.4	24.4

[1] See the corresponding footnotes under the table "Investing in the energy transition: Total cash capital expenditure" above for more details.

* Non-GAAP measure. See page 430.

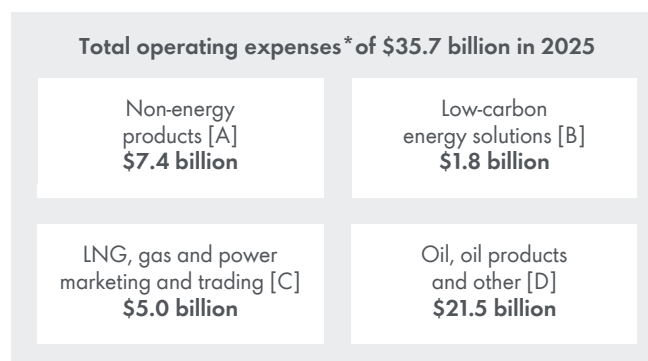
Operating expenses evolution by segment



Operating expenses is a measure of Shell's cost management performance, comprising the following items from the "Consolidated Statement of Income" on page 230: production and manufacturing expenses; selling, distribution and administrative expenses; and research and development expenses.

Total operating expenses* in 2025 were \$35.7 billion with a focus on structural cost savings and improved operational efficiency.

Energy transition: Total operating expenses



- [A] Products for which usage does not cause Scope 3, Category 11 emissions: Lubricants, Chemicals, Convenience Retailing, Agriculture and Forestry, Construction and Road.
 [B] Electric vehicle charging services, renewable power generation, nature-based solutions, green hydrogen, CCS. We define low-carbon energy products as those that have an average carbon intensity that is lower than that of conventional hydrocarbon products, assessed on a life-cycle basis.
 [C] LNG Production and Trading, Gas and Power Trading, and Energy Marketing.
 [D] Upstream segment, GTL, Refining and Trading, Marketing fuel and hydrocarbon sales, Shell Ventures, Corporate segment.

Total operating expenses* by segment for 2026 (excluding the one-off impact of the pension fund transition in the Netherlands from a defined benefit pension fund to a defined contribution plan [A]) are expected to be approximately \$9 billion for Upstream (2025: \$9.0 billion), \$4 billion for Integrated Gas (2025: \$4.2 billion), \$10 billion for Marketing (2025: \$10.6 billion), \$8 billion for Chemicals and Products (2025: \$8.4 billion), and around \$2 billion for Renewables and Energy Solutions (2025: \$2.6 billion).

- [A] For more details of the pension fund transition in the Netherlands see Note 24 to the Consolidated Financial Statements "Retirement benefits" on page 285.

Energy transition: Total operating expenses* by segment

Classification [1]	Segment	\$ billion			
		2025		2024	
					2023
Non-energy products [A]	Marketing	3.8	7.4	3.9	4.1
	Chemicals and Products	3.6		3.5	4.0
Low-carbon energy solutions [B]	Marketing	0.9	1.8	0.7	0.9
	Renewables and Energy Solutions	0.9		1.2	1.3
LNG, gas and power marketing and trading [C]	Integrated Gas	3.4	5.0	3.7	4.0
	Renewables and Energy Solutions	1.6		1.7	2.5
Oil, oil products and other [D]	Integrated Gas	0.8		0.8	0.8
	Upstream	9.0		9.8	9.8
	Marketing	6.0	21.5	6.0	6.2
	Chemicals and Products	4.8		4.9	5.6
	Renewables and Energy Solutions	0.0		0.0	0.0
	Corporate	0.9		0.7	0.8
Total		35.7	35.7	36.9	40.0

[1] See the footnotes under the table "Energy transition: Total operating expenses" above for more details.
 * Non-GAAP measure. See page 430.

Key aspects of Shell's financial resilience in the context of climate-related impacts are assessed and described in more detail in Note 4 to the "Consolidated Financial Statements" on page 244. This describes how Shell has considered climate-related impacts in key areas of the financial statements and how this translates into the valuation of assets and measurement of liabilities. Shell's financial statements are based on reasonable and supportable assumptions that represent management's best estimate of the range of economic conditions that may exist in the foreseeable future.

Sensitivity analysis using external, and often normative, climate change scenarios has been performed for the period covering asset life cycles. If these different price outlooks were used, this would impact the recoverability of certain assets recognised in the "Consolidated Balance Sheet" as at December 31, 2025.

As there is no single scenario that underpins our Operating Plan, sensitivity analysis has been conducted using a range of key assumptions to test the resilience of our asset base. This includes (but is not limited to):

- sensitivity analysis on asset carrying values using commodity price outlooks from external, and often normative, climate change scenarios;
- carbon price sensitivities;
- chemical and refining margins price sensitivities; and
- discount rate sensitivities.

Commodity price sensitivities

Oil and gas prices are one of the key assumptions that underpin Shell's financial statements, with the mid-price outlook informed by Shell's scenario planning representing management's reasonable best estimate. Price outlooks reflect a broad range of factors, including, but not limited to, future supply and demand, and the pace of growth of low-carbon solutions. The scenarios have been selected to illustrate the resilience of the asset base under a range of possible outcomes, including the price implications arising from the ambitious IEA Net Zero Emissions by 2050 Scenario (IEA NZE50), which provides a potential, yet narrow, pathway for the global energy system to achieve net-zero emissions by 2050. Sensitivities of asset carrying values to prices are under the assumption that all other factors in the models used to calculate impacts remain unchanged. Sensitivity analysis has been performed using price outlooks from:

1. Average prices from three 1.5-2°C external climate change scenarios: in view of the broad range of price outlooks across the various scenarios, the average of three external price outlooks was taken from IHS Markit/ACCS 2024, Woodmac WM AET-1.5 degree (2024 [A]), and IEA NZE50.

Applying this priceline to Integrated Gas assets of \$77 billion and Upstream assets of \$77 billion as at December 31, 2025, shows recoverable amounts that are \$13-17 billion and \$3-5 billion lower, respectively, than the carrying values as at December 31, 2025.

[A] The latest available published scenario.

2. Hybrid Shell Plan and IEA NZE50: for this Shell's mid-price outlook is applied for the next 10 years. Because of greater uncertainty, the IEA normative Net Zero Emissions scenario is applied for the period after 10 years. This gives less weight to the price-risk uncertainty in the first 10 years reflected in the Operating Plan period and applies more risk to the more uncertain subsequent periods.

Applying this priceline to Integrated Gas assets of \$77 billion and Upstream assets of \$77 billion as at December 31, 2025, shows recoverable amounts that are \$9-13 billion and \$1-3 billion lower, respectively, than the carrying values as at December 31, 2025.

3. A 1.5°C scenario, derived from IEA NZE50: this priceline applies the IEA normative Net Zero Emissions by 2050 scenario over the whole period under review and reflects the sensitivity to a pure net-zero emissions scenario from the IEA.

Applying this priceline to Integrated Gas assets of \$77 billion and Upstream assets of \$77 billion as at December 31, 2025, shows recoverable amounts that are \$15-19 billion and \$5-7 billion lower, respectively, than the carrying values as at December 31, 2025.

In addition, further sensitivities are provided of -10% or +10% to Shell's mid-price outlook, as an average percentage over the full period. A change of -10% or +10% to the mid-price outlook, as an average percentage over the full period, would result in around \$7-10 billion impairment or \$2-5 billion impairment reversal, respectively, in Integrated Gas and Upstream as at December 31, 2025.

Carbon pricing

We consider the potential costs associated with operational GHG emissions when we assess the resilience of projects. For each region, we have developed short-, medium- and long-term estimates of the future costs of carbon. These are reviewed and updated annually. See Note 4 to the "Consolidated Financial Statements" on page 244 for further details on our regional cost of carbon estimates.

Up to 2030, costs for carbon emissions estimates are largely climate-policy-driven through emissions trading schemes or taxation levied by governments, which varies significantly on a country-by-country basis. Beyond 2030, the costs for carbon emissions are assessed based on expectations for future carbon abatement technology costs and country/region-specific policies and conditions. Carbon costs vary by country due to differences in climate ambition, policy choice, and domestic economic and energy circumstances. In 2050, the estimated cost is trending towards \$50/tCO₂e (least developed countries with high economic/geopolitical risks) to \$185/tCO₂e (EU/UK) and \$230/tCO₂e (Norway) (RT25) in climate-leading geographies.

See "The resilience of Shell's strategy" on page 81 for more information on how carbon costs impact our resilience to climate-related risks, including sensitivity analysis.

See Shell's "Climate and Energy Transition Lobbying Report 2024", published in May 2025, for more information on Shell's advocacy across a range of issues, including carbon pricing.

Carbon pricing and discount rate sensitivities

The risk of stranded assets may increase in a higher-carbon-price scenario. Sensitivities of our asset carrying values to carbon prices have been based on the IEA NZE50 scenario to illustrate the resilience of asset carrying values to higher long-term carbon prices than those included in the Shell mid-price outlook.

Applying the IEA NZE50 carbon price scenario to Integrated Gas assets of \$77 billion and Upstream assets of \$77 billion, up to the end of life of these assets, shows recoverable amounts that are \$2-3 billion and up to \$1 billion lower, respectively, than the carrying values as at December 31, 2025.

Applying the IEA NZE50 carbon price scenario to Chemicals and Products assets of \$39 billion shows recoverable amounts that are up to \$2-3 billion lower than the carrying values as at December 31, 2025. For Chemicals and Products, increased carbon costs could potentially be recovered partially through increased product sales prices.

See "Carbon pricing" above for more information on our carbon price assumptions.

The discount rate applied for impairment testing is based on a nominal post-tax weighted average cost of capital (WACC) and is determined at 7.5%, except for power activities in the Renewables and Energy Solutions segment, where 6% is applied. The discount rate includes generic systematic risk for energy transition risk. In addition, cash flow projections applied in individual assets include specific asset risks, including risk of transition. An increase in generic systematic energy transition risk could lead to a higher WACC and consequently to a higher discount rate to be applied in impairment testing. We have used a 1% shift in discount rate for sensitivity analysis purposes as an indicator of the resilience of our asset base to incremental increases in our cost of capital.

An increase of the WACC of 1% – under the assumption that all other factors in the models used to calculate recoverability of carrying values remain unchanged – would lead to a change in the carrying value of \$3.6 billion for Integrated Gas and Upstream and no significant impairment in other segments.

See Note 4 to the "Consolidated Financial Statements" on pages 244-255 for further information on climate-related impacts in key areas of the financial statements.

Delivering progress in the energy transition

To ensure the resilience of our strategy, our responses to the risks and opportunities identified are:

- delivery through our integrated business model;
- decarbonisation of our energy value chains and operations; and
- a focus on demand-driven decarbonisation – recognising that we need to work with our customers to identify low-carbon energy solutions for their energy demands in the sectors where we have competitive advantages.

Our integrated approach allows us to withstand volatility in oil and gas markets. Our financial framework aims to enhance shareholder distributions and maintain discipline in capital allocation, and targets a strong credit investment grade rating. We are:

- Growing our integrated gas and LNG business: We plan to grow LNG sales by 4-5% (CAGR) a year through to 2030. Gas, including LNG, is a stabilising force in energy systems because it is versatile, flexible and reliable. Gas is a lower-carbon alternative to coal in power generation and industry, and to oil in transport. Gas can balance renewable energy to provide stability for national grids. We believe that supplying LNG will be the biggest contribution we will make through the next decade of the energy transition as we help to build the energy system of the future.
- Keeping liquids production stable: The role of oil and gas will be critical to the energy system for decades to come. We aim to sustain liquids production through to 2030 and will focus on basins where we have a competitive advantage. We will prioritise cost- and carbon-competitive molecules. The oil we are producing will increasingly come from our world-class deep-water business. We are developing deep-water fields into the 2030s by developing new projects near existing oil and gas fields, leveraging our technical expertise, strong partnerships and our model of simplification and replication.
- Transforming Downstream, Renewables and Energy Solutions: We are making clear choices and changes to enable this business to thrive through the energy transition. We are focusing on developing low-carbon energy and solutions where we have competitive advantages and are starting to see increasing demand. We are focusing on value over volume across all our businesses in Downstream, Renewables and Energy Solutions, and are working to unlock value in power and low-carbon solutions. This will support our climate-related targets and ambition, and position us for growth in hydrogen, CCS and low-carbon fuels.
- We are progressing significant abatement projects at our chemicals manufacturing plants and refineries; these key focused assets allow us to underpin our hydrocarbon energy sales and the sales of low-carbon energy products. Our energy transition plans for this decade across our Downstream, Renewables and Energy Solutions business are focused on: investing in biofuels, continuing to grow our integrated power business, growing our electric vehicle charging business where demand is strongest, and developing technologies related to CCS and carbon removals.

See "Our strategy" on pages 9-11.

Our research and development (R&D) activities are an important contributor to achieving our climate-related targets and ambition. They are an important way to address the technology risk as mentioned in "Transition risks" on page 76 and "Transition opportunities" on page 79.

In 2025, our R&D expenditure on projects that aim to contribute to decarbonisation was around \$485 million, representing about 41% of our total R&D spend, compared with around 45% in 2024. This includes expenditure on reducing GHG emissions:

- from our own operations, for example, by improving energy efficiency and electrification;
- from the fuels and other products we sell to our customers – for example, synthetic fuels, biofuels, and products made from low-carbon electricity, and hydrogen produced using renewable sources;
- by carbon capture, utilisation and storage applied to hydrogen production from natural gas and other carbon emissions; and
- for our customers, through renewable power generation, storage, e-mobility and other electrification solutions.

Other examples of R&D areas include safety; performance products, such as lubricants and polymers; automation and AI.

Decarbonising our value chains and operations

We seek to base the decarbonisation of our value chains and operations on an understanding of the decarbonisation strategies and plans of our customers and users of our energy products.

We are focused on decarbonising our own operations by:

- using more renewable electricity to power our operations;
- developing CCS for some of our facilities;
- improving the energy efficiency of our operations; and
- making portfolio changes such as acquisitions and investments in low carbon intensity projects, decommissioning facilities, and divesting assets while sustaining our liquids production.

If required, we may choose to use high-quality carbon credits to offset any remaining emissions from our operations, in line with the carbon mitigation hierarchy of avoid, reduce and compensate, or to meet local regulatory requirements.

We have set an interim target to achieve a 50% reduction in absolute Scope 1 and 2 emissions under our operational control by 2030 on a net basis, compared with 2016.

We set a target in 2021 to eliminate routine flaring from our upstream-operated assets by 2025, five years ahead of the World Bank's Zero Routine Flaring by 2030 initiative. In March 2024, we clarified that this target was subject to the completion of the sale of The Shell Petroleum Development Company of Nigeria (SPDC). Routine flaring burns gas that is not used or reinjected into wells, which is inefficient and contributes to climate change. We ceased routine flaring in January 2025, achieving our target to eliminate routine flaring from our upstream-operated assets by 2025. This was independent of the completion of the sale of SPDC to Renaissance on March 13, 2025. We also have a target to maintain methane emissions intensity for operated oil and gas assets below 0.2% and achieve near-zero methane emissions intensity by 2030. We plan to meet these targets by reducing methane emissions from flaring and venting; conducting leak detection and repair activities; and electrifying certain facilities to reduce gas combustion, such as at our Montney gas plant in Canada.

See Working to reduce our absolute Scope 1 and 2 emissions on page 97.

Supporting our customers to decarbonise

The transport sector is by far the largest market for our oil products. We are building on our customer relationships and expertise to help drive the decarbonisation of passenger cars, heavy-duty trucks, planes and ships. Changes to the supply of energy products and decarbonising the energy system require structural changes in the end use of energy.

This requires energy users to improve, update or replace equipment so that they can use carbon-based energy more efficiently, or switch to low- and zero-carbon energy. We are helping customers across different sectors to decarbonise their use of energy, for example by substituting the use of coal with LNG, replacing internal combustion engine vehicles with electric vehicles, transitioning heavy-duty transport to drop-in fuels and, in the future, converting to hydrogen and its derivatives if viable.

Such structural changes are expected to help trigger transitions along the supply chain of individual sectors and across sectors, including the production of energy and emissions over time. The IEA estimates these changes in the end use of energy will require substantial investment.

The World Energy Outlook 2025 report by the IEA includes an estimate that global annual energy investment in the NZE scenario needs to rise by nearly 50% over the next decade, with 90% of the spend directed towards clean energy, including renewables, grids and storage, efficiency and low-emissions fuels.

Emissions resulting from customer use of our energy products make up a large proportion of the emissions Shell reports. We offer our customers low-carbon energy products and services. We continue to evaluate market dynamics and exercise capital discipline as we work to meet our customers' need for affordable energy products and services. In this context, we stopped construction of our Rotterdam biofuels plant in the Netherlands because it would not have been competitive enough to meet our customers' need for affordable, low-carbon products. Shell has an important role to play in the evolving energy system. We provide the oil and gas people need today and we are helping to build the energy system of the future, with low-carbon energy products and solutions, including biofuels. Shell is one of the world's largest traders and suppliers of biofuels.

We will continue to:

- develop low-carbon alternatives to traditional fuel, and other low-carbon products - such as biofuels, hydrogen and renewable electricity;
- provide more renewable power solutions to customers by using the strength of our trading business to expand sales beyond our production volumes and growing our portfolio in select markets; and
- address any remaining emissions from conventional fuels with solutions such as CCS and high-quality carbon credits.

Energy transition in action – selection of portfolio changes and actions in 2025

Decarbonising our value chains and operations

In March 2025, the Wesseling site hydrocracker at the Shell Energy and Chemicals Park Rheinland in Germany stopped processing crude oil into petrol, jet fuel and diesel. Wesseling is being transformed to produce Group III base oils, used to make high-quality lubricants such as engine and transmission oils, as well as electric vehicle fluids.

We have continued to make portfolio changes including:

- the divestment of SPDC, which was the last remaining asset under Shell operational control conducting routine flaring. We had ceased routine flaring in January 2025, in advance of and independent of the sale of SPDC to Renaissance, which was completed in March 2025;
- the divestment of Shell Energy and Chemicals Park Singapore to CAPGC Pte. Ltd. in April 2025. The divestment was in line with Shell's ongoing efforts to high-grade its Chemicals and Products business; and
- the acquisition of RISEC Holdings, LLC and its 609 MW two-unit combined-cycle gas turbine power plant by our Renewables and Energy Solutions business in January 2025.

In September 2025, the Montney gas plant in British Columbia, Canada, replaced 14 natural gas compressor engines with electric motors. The new motors use electricity from the predominantly hydropower-supplied power grid, enabling an expected full-year annual reduction of over 149,000 tonnes of CO₂e.

Construction continued on the REFHYNE II 100 MW hydrogen electrolyser at Shell Energy and Chemicals Park Rheinland. In November 2025, Shell Energy Europe Limited signed two separate power purchase agreements (PPA) in Germany with Nordsee One GmbH and Solarkraftwerk Halenbeck-Rohlsdorf I/II GmbH. The agreements will secure a significant proportion of the renewable electricity needed to power the REFHYNE II hydrogen electrolyser.

In the Netherlands, construction of Holland Hydrogen I, one of Europe's largest renewable hydrogen plants, is progressing well, and we expect to start commissioning towards the end of 2026, with production ramp-up in 2027.

Construction continued at the Polaris carbon capture facility at the Shell Energy and Chemicals Park Scotford in Alberta, Canada. Polaris is designed to capture around 650,000 tonnes of CO₂ annually from the refinery and chemicals complex.

Supporting our customers to decarbonise

By the end of 2025, the number of public charge points globally at Shell forecourts, on-street locations, mobility hubs and other sites, such as supermarkets, was almost 88,000 compared with almost 73,000 in 2024.

In June 2025, Shell Energy Europe Limited and Vodafone Procure & Connect launched a pilot project to explore how battery storage could support more flexible and sustainable energy use in the future. The project will assess how large-scale batteries participate in the grid and inform energy management strategies. Vodafone Procure & Connect will access part of the operational benefits from Shell's 100 MW, 3-hour battery site in Hampshire – one of the UK's largest grid-connected facilities.

In March 2025, the Northern Lights joint venture (Shell interest 33.3%) took an FID on moving forward with Phase 2 of the project, following a commercial agreement with Swedish energy provider, Stockholm Exergi, for the cross-border transport and storage of up to 900,000 tonnes of biogenic CO₂ annually for 15 years. (See page 68 for more details of our Northern Lights CCS venture).

In September 2025, Google selected Shell Energy Europe Limited as its renewable energy supply manager in the UK, under the USA-based technology company's Carbon-Free Energy supply model to reach its goal of running entirely on clean energy by 2030.

Metrics used by Shell to assess climate-related risks and opportunities in line with our strategy and risk management process ¹

This section sets out the metrics we use to track progress against our climate-related targets and ambition. These metrics are as follows:

- Metrics related to our own operations:
 - absolute Scope 1 and 2 emissions under operational control, with a 2016 baseline; and
 - routine flaring and methane emissions intensity under operational control.
- Metrics related to emissions from the products we sell:
 - the NCI of the energy products we sell (equity basis), with a 2016 baseline; and
 - customer emissions from the use of our oil products (Scope 3, Category 11, equity basis), with a 2021 baseline.
- Performance indicators for the energy transition performance condition reflected in the remuneration of senior management and employees as set out in "Linking Shell's emissions targets to remuneration" on page 98.
- Additional metrics associated with the resilience of Shell's strategy to climate-related risks and opportunities, including information on capital allocation between our business segments and the sensitivity of our assets to carbon pricing, discount rate and commodity price assumptions as set out in "Resilience of Shell's strategy to different climate-related scenarios" on page 81.
- Metrics and targets in respect of climate-related environmental risks as set out in "Metrics and targets in respect of climate-related environmental risks" on page 95.

Scope 1, 2 and 3 emissions and related risks ¹

Scope 1 and 2 emissions under our operational control and Scope 3 emissions on an equity basis are reported in this section. For details of the "Climate-related risks and opportunities identified by Shell over the short, medium and long term" see pages 75-79.

Scope 1 and 2 emissions

In 2025, total combined Scope 1 and 2 GHG emissions (net) from assets and activities under Shell operational control were 53 million tonnes of CO₂e, reflecting a 36% reduction compared with 2016, the base year for our target to halve these emissions by 2030.

Total combined Scope 1 and 2 GHG emissions (net) were 9% lower compared with 2024 due to portfolio changes, reductions from abatement projects and downtime at various sites. Key portfolio changes included the completion of the sale of The Shell Petroleum Development Company of Nigeria Limited (SPDC) by our Upstream business in March 2025, the sale of Shell Energy and Chemicals Park Singapore by our Chemicals and Products business in April 2025 and the acquisition of RISEC Holdings, LLC and its 609 MW two-unit combined-cycle gas turbine power plant by our Renewables and Energy Solutions business in January 2025. Reductions from abatement projects mainly consisted of transformation projects at the Shell Energy and Chemicals Park Rheinland in Germany, compressor electrification in Canada and catalyst improvements in Qatar.

Drivers of Scope 1 and 2 emissions

Gross direct GHG emissions (Scope 1, operational control boundary) were 46 million tonnes of CO₂e in 2025. This was lower than in 2024 (50 million tonnes of CO₂e) mainly due to portfolio changes and abatement projects.

Gross indirect GHG emissions (Scope 2, operational control boundary, using a market-based method) fell from 8 million tonnes of CO₂e in 2024 to 7 million tonnes CO₂e in 2025, mainly driven by divestments.

Examples of our energy efficiency projects can be found on page 102.

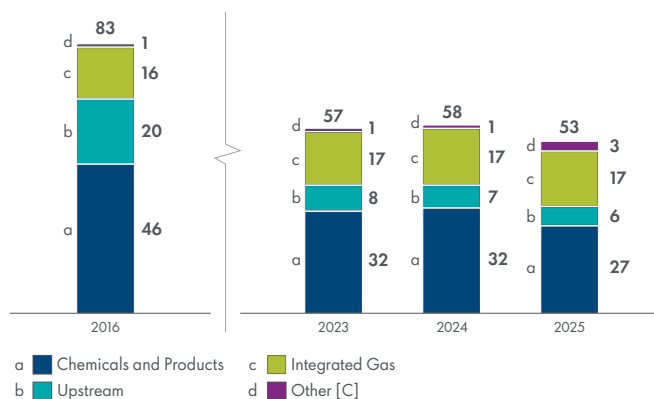
Scope 1 and 2 emissions [D] [E]

	million tonnes CO ₂ e			
(operational control boundary)	2025	2024	2023	2016
Scope 1 emissions (gross) [A]	46	50	50	72
Scope 2 emissions (gross) [B]	7	8	7	11
Carbon credits [C]	—	0.1	—	—
Total Scope 1 and 2 emissions (net) [F]	53	58	57	83

- [A] Total direct GHG emissions from assets and activities under our operational control. It includes emissions from the production of energy and non-energy products. Scope 1 emissions are reported gross without the inclusion of carbon credits.
- [B] Total indirect GHG emissions from imported energy from assets and activities under our operational control using a market-based method. It includes imported energy used for the production of energy and non-energy products. Scope 2 emissions are reported gross without the inclusion of carbon credits.
- [C] Carbon credits used to offset Scope 1 emissions for compliance purposes, such as under the Australian Safeguard Mechanism.
- [D] Oil and gas industry guidelines from Ipieca indicate that several sources of uncertainty can contribute to the overall uncertainty in Scope 1 and 2 emissions inventories.
- [E] Figures disclosed are rounded. Rounding differences can occur between the total combined Scope 1 and 2 absolute GHG emissions disclosed in this Report and the sum of components individually rounded to the nearest million tonnes.
- [F] We measure total combined Scope 1 and 2 GHG emissions compared with a 2016 baseline, on a net basis. The 2016 baseline may be recalculated if an acquisition or a divestment has an impact of more than 10% on total Scope 1 and 2 emissions.

Scope 1 and 2 emissions (net) by business [A] [B]

million tonnes CO₂e

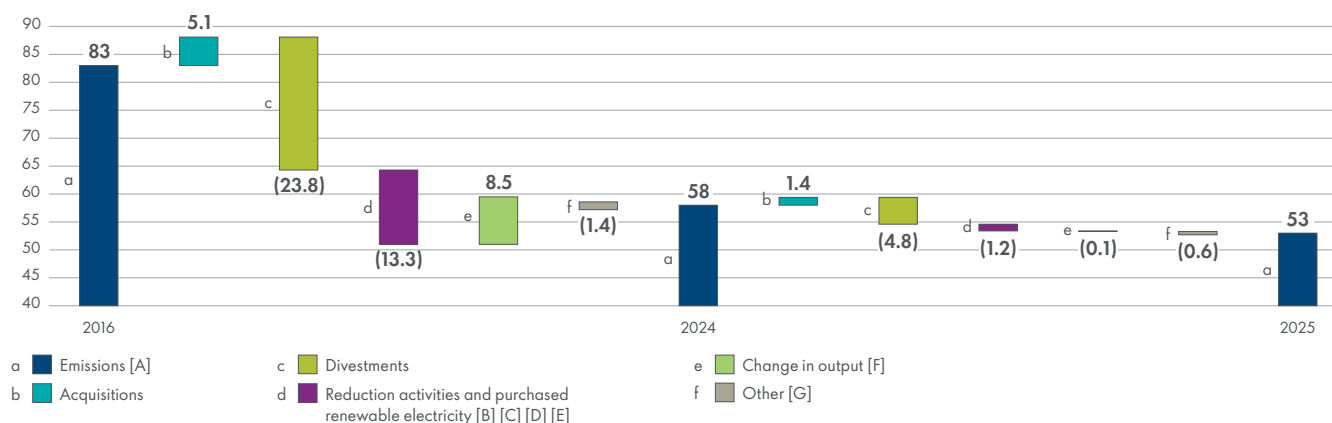


- [A] Total direct (Scope 1) and energy indirect (Scope 2) GHG emissions from assets and activities under the operational control boundary, net of carbon credits. It includes emissions from the production of energy and non-energy products. For Scope 2, we used a market-based method.
- [B] Figures disclosed are rounded. The split between Scope 1 and 2 may not add up to the total due to rounding.
- [C] Renewables and Energy Solutions, Marketing and functions (Projects & Technology and Real Estate).

Drivers of absolute Scope 1 and 2 emissions change

Scope 1 and 2 GHG emissions (net): Changes from 2016 to 2024 and from 2024 to 2025

million tonnes CO₂e



[A] Total Scope 1 and 2 emissions, rounded to the nearest million tonnes. Scope 2 emissions were calculated using a market-based method.

[B] In addition to reductions from GHG abatement and energy efficiency projects, this category includes reductions from permanent shutdowns and conversion of existing assets.

[C] Excludes 8.8 million tonnes of CO₂ captured and sequestered by the Shell-operated Quest CCS facility in Canada in 2016-2024.

[D] Excludes 0.9 million tonnes of CO₂ captured and sequestered by the Shell-operated Quest CCS facility in Canada in 2025.

[E] Of the 1,238 thousand tonnes of reduction activities and purchased renewable electricity in 2025, around 20 thousand tonnes related to purchased renewable electricity.

[F] Change in output relates to changes in production levels, including those resulting from shutdowns and turnarounds as well as production from new facilities.

[G] In 2025, mainly driven by measurement improvements.

Routine flaring

Routine flaring of associated gas occurs during normal oil production where it is not possible to transport the gas to market, use it on site or reinject it.

Since 2016, routine flaring from upstream operations under Shell operational control reduced from 1.1 million tonnes to around 10 thousand tonnes in 2024. With SPDC ceasing routine flaring in January 2025, we achieved our target to eliminate routine flaring by 2025. This was independent of the sale of SPDC to Renaissance completed on March 13, 2025.

Total routine flaring [A]

	million tonnes			
(operational control boundary)	2025	2024 [B]	2023	2016
Total hydrocarbons flared in routine flaring	—	0.01	0.1	1.1

[A] Routine flaring of associated gas occurs during normal oil production where it is not possible to transport the gas to market, use it on site or reinject it.

[B] Revised from 0.1 million tonnes to 0.01 million tonnes following a reclassification between routine and non-routine flaring, with no change to total hydrocarbons flared in 2024.

Total routine and non-routine flaring at our Integrated Gas and Upstream facilities was 0.4 million tonnes in 2025, compared with 0.6 million tonnes in 2024, a reduction mainly driven by the sale of SPDC.

Methane intensity

In 2025, we continued to deliver methane emissions intensities well below our 0.2% target, with overall methane emissions intensity at 0.04% for Shell-operated oil and gas assets with marketed gas and 0.002% for Shell-operated oil and gas assets without marketed gas.

Total methane emissions from assets under Shell operational control (including Integrated Gas, Upstream, Chemicals and Products, Marketing and Renewables and Energy Solutions assets) were 31 thousand tonnes in 2025 compared with 33 thousand tonnes in 2024 following divestments, reduced venting and infrastructure improvements which more than offset increases from improved measurement-based reporting practices, an increase in fugitive emissions at Shell Nigeria Exploration and Production Company (SNEPCo), and updated methods for estimation of sources for biogas process venting at Renewable Natural Gas sites. Total methane emissions under Shell operational control were reduced by 78% between 2016 (138 thousand tonnes) and 2025.

We believe our methane emissions are quantified according to industry best practice. Methane emissions include those from unintentional leaks, venting and incomplete combustion, for example in flares and turbines.

Methane emissions intensity

	Percentage			
(operational control boundary)	2025	2024	2023	2016
Methane emissions intensity – assets with marketed gas [A]	0.04%	0.04%	0.05%	0.10%
Methane emissions intensity – assets without marketed gas [B]	0.002%	0.001%	0.001%	0.03%

[A] Methane emissions intensity from all Shell-operated oil and gas assets that market their gas (including LNG and GTL assets), defined as the total volume of methane emissions in normal cubic metres (Nm³) per total volume of gas available for sale in Nm³.

[B] Methane emissions intensity from all Shell-operated oil and gas assets that do not market their gas (such as where gas is reinjected), defined as the total mass of methane emissions in tonnes per total mass of oil and condensate available for sale in tonnes.

Scope 3 and NCI

NCI performance

In 2025, Shell's NCI was 71 grams of carbon dioxide equivalent per megajoule of energy (gCO₂e/MJ). At a comparable level with 2024, our NCI in 2025 benefited from higher sales of renewable power and lower sales of oil products, partly offset by fewer carbon credit retirements. Shell's NCI reduction of 9.0% compared with the 2016 baseline meets our interim target of a reduction of 9-13% in 2025.

NCI performance

(equity boundary)		2025	2024	2023	2016
NCI [A] [B]	gCO ₂ e/MJ	71	71	72	78
Estimated total energy delivered by Shell [C]	trillion (10 ¹²) MJ	15.63	15.85	16.13	20.80
Estimated total GHG emissions included in NCI (net) [D]	million tonnes CO ₂ e	1,108	1,122	1,158	1,615
Carbon credits	million tonnes CO ₂ e	5.5	16.4	20.0	—
Estimated total GHG emissions (gross)	million tonnes CO ₂ e	1,113	1,139	1,178	1,615

[A] Rounded to the nearest gCO₂e/MJ.

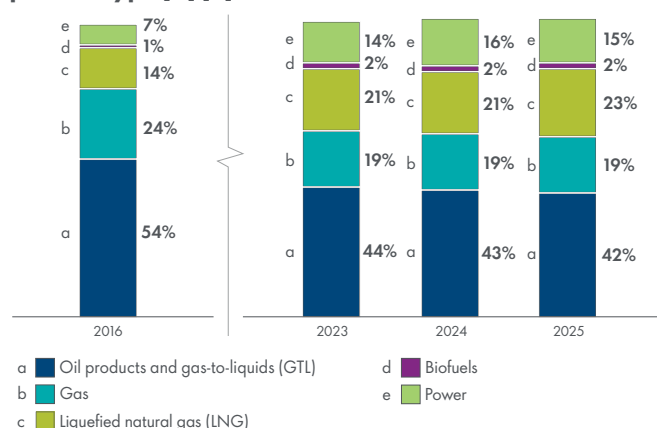
[B] We measure our NCI performance compared with a 2016 baseline. The NCI targets and baseline are not adjusted for the impact of acquisitions and divestments, which could have a material impact on meeting the NCI targets.

[C] Volume of energy products sold, aggregated on an energy basis, with power represented as fossil equivalent. Energy products consist of energy oil products (gasoline, diesel, kerosene, fuel oil and LPG), GTL, biofuels, LNG, pipeline gas and power.

[D] Estimated total GHG emissions included in NCI (net) are the product of the NCI and the total energy delivered by Shell. Adding emissions offset using carbon credits gives the Estimated total GHG emissions included in NCI (gross).

As part of our strategy, we aim to increase the share of low-carbon products in our energy product sales, which is the biggest driver for reducing our NCI.

Share of estimated total energy delivered per energy product type [A] [B]



[A] Percentage of delivered energy may not add up to 100% because of rounding.

[B] Total volume of energy products sold, aggregated on an energy basis (lower heating value) with power represented as fossil equivalents.

Our ability to change the emissions intensity of each energy product varies, depending on the product type:

- Hydrocarbon fuels - emissions from end use by customers are by far the biggest contributors to the carbon intensity of the product. As a result, the emissions intensity of hydrocarbon fuels is expected to stay relatively unchanged over time. This is why we are focused on helping our customers decarbonise.
- Biofuels - can vary significantly in intensity depending on the feedstock and production process used.
- Power - the emissions intensity of power can be highly variable depending on how it has been generated. The proportion of our renewable power sales and the generation mix in countries where we sell power to the market both affect Shell's overall power mix and its resulting emissions intensity.

We sell more energy products than we produce ourselves. Therefore, when we estimate total GHG emissions included in NCI, we include emissions from energy products that we produce ourselves and from the products that we purchase from others for resale. This is reflected in the NCI scope shown in the chart on page 93.

Life-cycle carbon intensities for energy product categories included in the NCI calculation are summarised in the table below:

Carbon intensity of energy products

	gCO ₂ e/MJ			
	2025	2024	2023	2016
Oil products and gas-to-liquids (GTL)	85	86	87	87
Gas	65	66	66	66
Liquefied natural gas (LNG)	70	70	70	73
Biofuels	33	34	34	38
Power [A]	46	48	49	60

[A] Emissions included in the carbon intensity of power have been calculated using a market-based method.

Drivers of absolute Scope 3 emissions change in 2025

Scope 3 emissions associated with our energy product sales were 1,065 million tonnes CO₂e, compared with 1,084 million tonnes CO₂e in 2024. Higher emissions from the use of the liquefied natural gas (LNG) we sell were more than offset by lower emissions from the use of our oil products sold and lower emissions associated with our purchases of non-renewable power from third parties.

Emissions from Scope 3, Categories 1, 3, 9 and 11, related to the sale of energy products, are the most significant categories for Shell. Emissions from the use of our energy products (Category 11) form the largest component of the indirect Scope 3 emissions we report. As we sell more products than we produce or refine ourselves, the emissions associated with the products we purchase from third parties are also material, as reported under Category 1 for hydrocarbon products, such as oil products, gas and LNG, and Category 3 for power. Although quantitatively less significant, emissions reported under Category 9 are significant to Shell for consistency with the boundaries of our NCI. Other Scope 3 categories have been assessed to be quantitatively and qualitatively insignificant.

Scope 3 emissions by category [A] [B]

	million tonnes CO ₂ e			
(equity boundary)	2025	2024	2023	2016
Scope 3, Category 1: purchased goods and services	122	119	130	179
Scope 3, Category 3: fuel and energy-related activities	103	117	112	89
Scope 3, Category 9: downstream transport and distribution [C]	4	3	3	—
Scope 3, Category 11: use of sold products	836	845	878	1,252
	1,065	1,084	1,123	1,520

[A] Categorised using the definitions from the GHG Protocol's Corporate Value Chain (Scope 3) Standard.

[B] Ipieca notes that, due to the diversity of Scope 3 emissions, sources and the fact that these emissions occur outside the company's boundaries, the emissions estimates may be less accurate or may have a high uncertainty.

[C] An estimate of Scope 3, Category 9 could not be performed for 2016.

Drivers of absolute Scope 3, Category 11 oil products emissions change in 2025

In 2025, Scope 3, Category 11 emissions from the use of our oil products were 467 million tonnes CO₂e, a reduction of 4.9% compared with 2024. This reduction was driven by lower sales in our Products business following completion of the sale of the Shell Energy and Chemicals Park Singapore in April 2025 and by lower Mobility sales.

At the end of 2025, we achieved a reduction of 17.9% compared with 2021, as part of our ambition to reduce customer emissions from the use of our oil products (Scope 3, Category 11) by 15-20% by 2030 compared with 2021.

Customer emissions from the use of our oil products

	million tonnes CO ₂ e			
(equity boundary)	2025	2024	2023	2021
Scope 3, Category 11: use of sold products (oil products)	467	491	517	569

Carbon credits

In 2025, Shell accounted for the retirement of 5.8 million carbon credits, of which 5.5 million were related to our NCI (including 2.0 million linked to the sale of energy products).

We carefully source and screen the credits we purchase and retire from the market. Of our total carbon credit retirements for 2025, 59% were certified by the Verra Verified Carbon Standard Program (VCS), 22% by Gold Standard, 10% by the ACR carbon crediting programme and 9% via Climate Action Reserve.

Carbon credit retirements [A]

	million carbon credits [B]			
(equity boundary)	2025	2024	2023	2016
Included in Shell's NCI metric [C]	5.5	16.4	20	—
Excluded from Shell's NCI metric [D]	0.3	0.9	1.8	—
	5.8	17.3	21.8	—

[A] Credits related to transactions occurring in the financial year irrespective of the actual retirement date. Retirements from registries may take place after the year-end. Excludes carbon credit transactions executed by Shell on behalf of/with third parties without a link to Shell activities.

[B] One carbon credit represents the avoidance or removal of one metric tonne of CO₂ equivalent.

[C] Carbon credits associated with the sale of energy products and carbon credits used to compensate for Shell Group emissions, including operational emissions and emissions associated with the use of sold products.

[D] Carbon credits retired in relation to sales of non-energy products and Shell's internal activity, e.g. corporate travel.

Basis of preparation

NCI

Shell's NCI is the average intensity, weighted by sales volumes, of the energy products sold by Shell. It is tracked, measured and reported using Shell's Net Carbon Footprint (NCF) methodology.

NCI objective

Shell's NCI provides an annual measure of the life-cycle emissions intensity of the portfolio of energy products sold. The intended use of the NCI metric is to track progress in reducing the overall carbon intensity of the energy products sold by Shell. NCI measures emissions associated with each unit of energy we sell, compared with a 2016 baseline. It reflects changes in sales of oil and gas products, and changes in sales of low-carbon products such as biofuels and renewable electricity.

NCI definition

The NCI is calculated on a life-cycle basis and as such includes GHG emissions – on an equity basis – from several sources, including:

- direct GHG emissions from Shell operations;
- indirect GHG emissions from the generation of energy consumed by Shell;
- indirect emissions associated with the production, processing and transport of third-party products we buy; and
- indirect GHG emissions from the use of the products we sell.

The NCI is not a mathematical derivation of total emissions divided by total energy, nor is it an inventory of absolute emissions. It is a weighted average of the life-cycle CO₂ intensities of different energy products, normalising them to the same point relative to their final end use. The use of a consistent functional unit gCO₂e/MJ allows like-for-like comparisons and the aggregation of individual life-cycle intensities for a range of energy products, including renewable power.

Emissions from other parts of the product life cycle are also included, such as those from the extraction, transport and processing of crude oil, gas or other feedstocks and the distribution of products to our customers. Also included are emissions from parts of this life cycle not owned by Shell, such as the extraction of oil and gas processed by Shell but not produced by Shell; or from the production of oil products and electricity marketed by Shell that have not been processed or generated at a Shell facility.

We also take into account emissions offset through the use of carbon credits and mitigation actions, such as the use of CCS technology.

See "Scope of NCI" on page 93 for details of the supply chains and steps in the product life cycles that are included in the NCF methodology.

The following GHG emissions are not included in the NCI:

- emissions from production, processing, use and end-of-life treatment of non-energy products, such as chemicals and lubricants;
- emissions from third-party processing of sold intermediate products, such as the manufacture of plastics from feedstocks sold by Shell;
- emissions associated with the construction and decommissioning of production and manufacturing facilities;
- emissions associated with the production of fuels purchased to generate energy on-site at a Shell facility;
- other indirect emissions from waste generated in operations, business travel, employee commuting, transmission and distribution losses associated with imported electricity, franchises and investments; and
- emissions from capital goods, defined by the GHG Protocol as including fixed assets or property, plant and equipment, and other goods and services not related to purchased energy feedstocks sourced from third parties or energy products manufactured by third parties and sold by Shell.

The NCI calculation uses Shell's energy product sales volumes data, as disclosed in this report where relevant. This excludes certain sales volumes, such as:

- certain contracts held for trading purposes reported net rather than gross. Business-specific methodologies to net volumes have been applied in oil products and pipeline gas and power. Paper trades that do not result in physical product delivery are excluded; and
- retail sales volumes from markets where Shell operates under trademark licensing agreements.

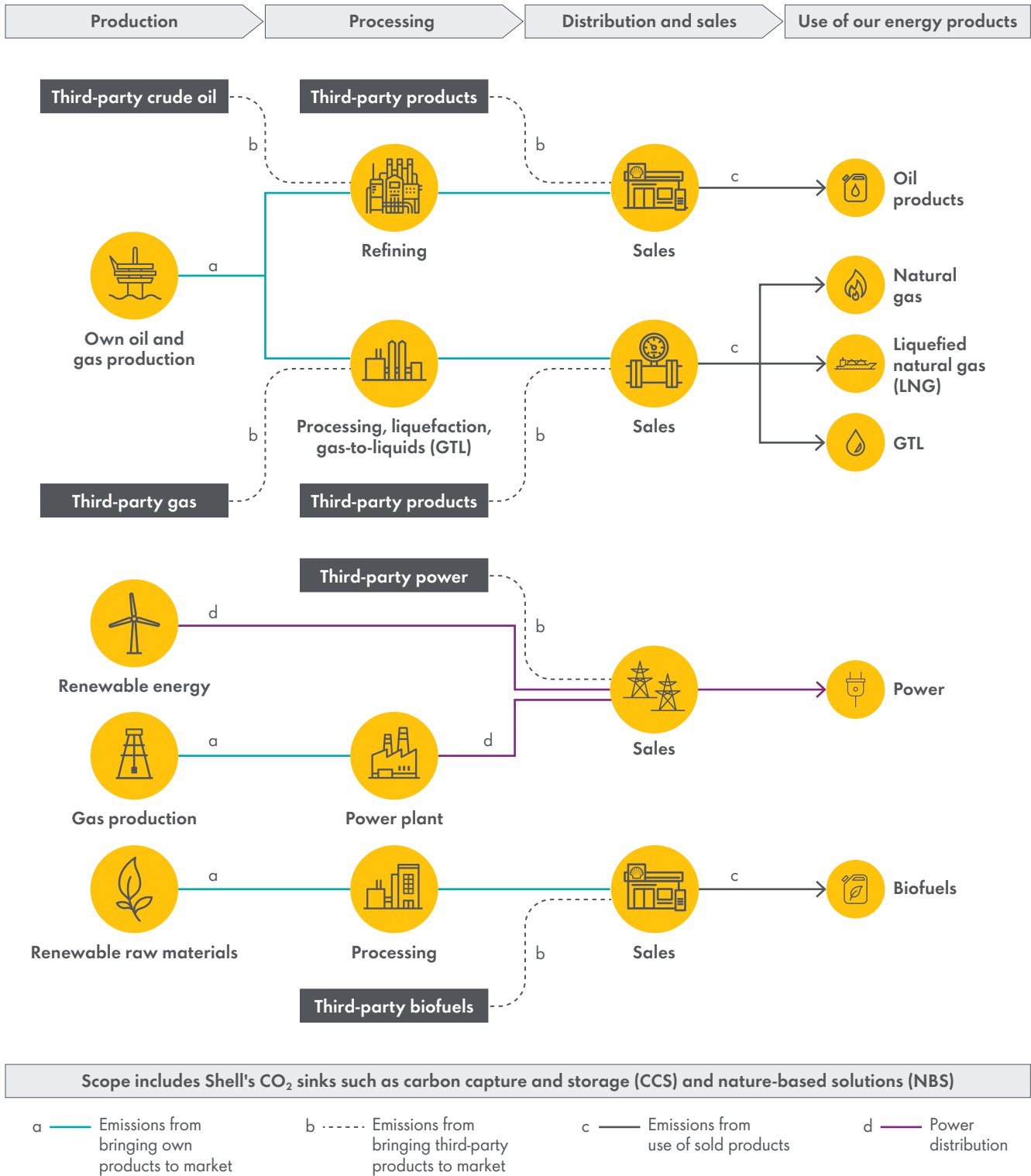
The energy products included in the NCI calculation are oil products (gasoline, diesel, kerosene, fuel oil and LPG), GTL, biofuels, LNG, pipeline gas and power.

We review the NCI methodology annually to ensure it reflects changing energy products, relevant data inputs and simplification opportunities. See our NCF methodology documentation on [shell.com](https://www.shell.com) for further information.

NCI baseline and restatement policy

We measure our NCI performance compared with a 2016 baseline. The NCI targets and baseline are not adjusted for the impact of acquisitions and divestments, which could have a material impact on meeting the NCI targets. The 2016 baseline may be recalculated as a result of changes in estimates with a cumulative impact of 2% or more on the NCI value in any historically disclosed year.

Scope of NCI



Basis of preparation – absolute Scope 1, 2 and 3 emissions

We follow the GHG Protocol's Corporate Accounting and Reporting Standard, which defines three scopes of GHG emissions:

- Scope 1: direct GHG emissions;
- Scope 2: indirect GHG emissions from the generation of purchased energy; and
- Scope 3: other indirect GHG emissions, including emissions associated with the use of sold products.

GHG emissions comprise CO₂, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, sulphur hexafluoride and nitrogen trifluoride, with CO₂ and methane being the most significant contributors.

Scope 1 and 2 emissions

Our GHG inventory is prepared in line with the requirements outlined in the ISO 14064-1:2018 Specification with Guidance at the Organizational Level for Quantification and Reporting of Greenhouse Gas Emissions and Removals and the GHG Protocol's Corporate Accounting and Reporting Standard.

In line with external standards, we aggregate GHG emissions into tonnes CO₂e by applying global warming potential (GWP) factors to non-CO₂ GHGs. With effect from 2023, these factors are taken from the IPCC's Fifth Assessment Report (AR5) over a 100-year period, as required by the UK Government GHG Conversion Factors for Company Reporting. GHG emissions are aggregated and consolidated from emission source.

We use the operational control boundary for target setting and management of Scope 1 and 2 GHG emissions because it reflects our ability to directly control operations by applying our own operating policies and standards. Under this approach, in line with the GHG Protocol, we account for 100% of the GHG emissions from assets and activities under our operational control, irrespective of our ownership percentage. Assets under operational control include:

- assets wholly owned by Shell;
- joint operations where Shell has been designated as the operator under the terms of the joint arrangement; and
- assets leased and operated by Shell, such as leased maritime vessels where Shell holds the Safety Management Document of Compliance.

Emissions from maritime vessels for which Shell only provides technical services, are not included in our operational control boundary.

Scope 1 emissions

All significant sources were included in our Scope 1 inventory. These sources comprise:

- combustion of carbon-containing fuels in stationary equipment (e.g. boilers and gas turbines) for energy generation;
- combustion of carbon-containing fuels in mobile equipment (e.g. trucks, vessels and mobile rigs);
- flares;
- venting and emissions from industrial processes (e.g. hydrogen plants and catalytic cracking units); and
- fugitive emissions, including piping and equipment leaks and non-routine events.

Our Scope 1 emissions follow the GHG Protocol guidance. As a result, the following are not included in our reported Scope 1 emissions:

- CO₂ emissions from biogenic sources, such as biofuels or biomass (however, methane and nitrous oxide emissions from biogenic sources are included);
- captured CO₂ that was subsequently sold or otherwise transferred to third parties; and
- CO₂ captured and sequestered using CCS technologies.

Scope 1 emissions are presented on a gross basis.

Scope 2 emissions

All significant sources were included in our Scope 2 inventory. Sources included comprise indirect emissions from purchased and consumed electricity, steam and heat. We did not identify any assets with imported cooling or compressed air used for energy purposes.

Scope 2 emissions are calculated using the market- and location-based methods separately as defined by the GHG Protocol Scope 2 Guidance. Scope 2 emissions are presented on a gross basis.

Carbon credits

Our target to halve total Scope 1 and 2 GHG emissions by 2030 has been set on a net basis, including emissions offset by carbon credits.

Baseline and restatement policy

We measure our total combined Scope 1 and 2 GHG emissions performance compared with a 2016 baseline, on a net basis. The 2016 baseline may be recalculated if an acquisition or a divestment has an impact of more than 10% on total Scope 1 and 2 emissions.

Scope 3 emissions

This report provides Scope 3 emissions associated with our energy product sales. Emissions were consolidated using the equity boundary approach. Under this approach, we reported the share of emissions from energy products sold by Shell, including those sourced from third parties.

Emissions from Scope 3, Categories 1, 3, 9 and 11, related to the sale of energy products, are the most significant categories for Shell. Emissions from the use of our energy products (Category 11) form the largest component of the indirect Scope 3 emissions we report. As we sell more products than we produce or refine ourselves, the emissions associated with the products we purchase from third parties are also material, as reported under Category 1 for hydrocarbon products, such as oil products, gas and LNG, and Category 3 for power. Although quantitatively less significant, emissions reported under Category 9 are significant to Shell for consistency with the boundaries of our NCI. Other Scope 3 categories have been assessed to be quantitatively and qualitatively insignificant.

The calculation of Scope 3, Category 11 emissions uses energy product sales volumes data, disclosed in this report where relevant. These sales volumes exclude certain contracts held for trading purposes and are reported net rather than gross. Business-specific methodologies have been applied to net volumes of oil products, pipeline gas and power. Paper trades that do not result in physical product delivery are excluded. Retail sales volumes from markets where Shell operates under trademark licensing agreements are not included in the sales volumes reported by Shell and are therefore excluded from Scope 3 emissions.

Scope 3, Category 1 – purchased goods and services

This category includes well-to-tank emissions from purchased third-party unfinished and finished energy products excluding electricity (which is reported separately under Category 3: fuel and energy-related activities and not included in Scope 1 or 2). Emissions from purchased non-energy products are not included.

Emissions in this category are estimated using well-to-tank emission factors for crude oil, natural gas, refined oil products (such as gasoline, and diesel), LNG and biofuels. Because the emission factors include transport, we do not estimate emissions from the transport of purchased third-party products separately.

Scope 3, Category 3 – fuel and energy-related activities (not included in Scope 1 and 2)

This category includes well-to-wire emissions from purchased third-party electricity sold by Shell, calculated using a market-based method. Emissions are not adjusted for any potential double-counting of sold natural gas that may have been used for generating this electricity.

This category does not include:

- indirect emissions from the generation of imported energy (steam, heat or electricity consumed by our assets) – these emissions are reported separately as Scope 2 emissions; and
- well-to-tank emissions from purchased electricity, steam and heat consumed by our assets (i.e. Scope 3 emissions from the extraction, refining and transport of primary fuels before their use in the generation of electricity or steam).

Scope 3, Category 9 – downstream transport and distribution

This category includes estimated emissions from the transport and distribution of energy products produced or refined by Shell. It does not include the emissions associated with transporting third-party products, which are included in Scope 3, Category 1. To avoid double-counting across emission scopes, emissions from transport activities which are already included in our Scope 1 and 2 equity emissions are excluded from this category.

Scope 3, Category 11 – use of sold products

This category includes estimated emissions from the use of sold energy products, such as LNG, GTL, pipeline gas, refined oil products and biofuels. These emissions relate to products manufactured and sold by Shell and third-party products sold by Shell.

This category does not include non-energy products that may have been combusted during use (e.g. lubricants).

Biogenic emissions

CO₂ emissions from biogenic sources related to the combustion of sold biofuels are estimated but, in line with GHG Protocol guidance and ISO 14064-1:2018, not included in Scope 3, Category 11. Methane and nitrous oxide emissions from biogenic sources are included in Scope 3, Category 11.

It is assumed that the presence of biogenic emissions associated with other Scope 3 categories is negligible.

Customer emissions from the use of our oil products

Our ambition to reduce customer emissions from the use of our oil products is a subset of Scope 3, Category 11 emissions, focusing on the use of refined oil products.

We measure these emission reductions compared with a 2021 baseline. The 2021 baseline may be recalculated in the event of a revision of our sales of oil products or in the event of other changes to emission factors subject to a 2% cumulative threshold.

Metrics and targets in respect of climate-related environmental risks

We monitor physical risk exposures, whether climate-related or not, water use, emissions to air and water, biodiversity and waste generated from our operations. Where relevant, we may manage our environmental performance by establishing specific targets.

See "Environment" on pages 120-122.

Targets used by Shell to manage climate-related risks and opportunities and performance against targets

Our response to the energy transition risk focuses on decarbonising our value chain. This section sets out our climate targets, which are focused on reducing our NCI and our absolute emissions, as presented on pages 96-97. Shell's material climate-related risks and opportunities are set out in the "Climate-related risks and opportunities identified by Shell over the short, medium and long term" section on pages 75-79.

We have set intensity targets and absolute targets and an ambition over the short, medium and long term to track our performance over time (as summarised below). The targets are forward-looking targets based on management's current expectations and certain material assumptions and, accordingly, involve risks and uncertainties that could cause actual results, performance or events to differ materially from those expressed or implied herein.

We believe that the total net absolute emissions included in our NCI peaked in 2018 at 1.7 gigatonnes of carbon dioxide equivalent (GtCO₂e).

We are seeking to reduce emissions from our own operations, including the production of oil and gas. More than 90% of the total emissions we include within our NCI boundary are indirect emissions associated with the purchase of third-party products and with the end-use emissions of energy products we sell, so we are also working with our customers to support them in transitioning to low-carbon products and services.

In October 2021, we set targets to:

- reduce Scope 1 and 2 absolute emissions from assets and activities under our operational control (including divestments) by 50% by 2030 compared with the 2016 baseline, on a net basis;
- maintain methane emissions intensity for operated oil and gas assets below 0.2% and achieve near-zero methane emissions intensity by 2030; and
- eliminate routine flaring from our upstream-operated assets by 2025. In March 2024, we clarified that this target was subject to the completion of the sale of SPDC.

In March 2024, we set revised targets to reduce the NCI of the energy products we sell by 9-13% by 2025, 15-20% by 2030 and 100% by 2050, compared with a 2016 baseline.

The NCI metric measures the pace of transition by tracking our progress in reducing the overall carbon intensity of the energy products sold by Shell. NCI measures emissions associated with each unit of energy we sell, compared with a 2016 baseline. It reflects changes in sales of oil and gas products, and changes in sales of low-carbon products, such as biofuels and renewable electricity. Unlike Scope 1 and 2 emissions, reducing the NCI of the products we sell requires action by both Shell and our customers, with the support of governments and policymakers to create the right conditions for change.

In March 2024, we set an ambition to reduce customer emissions from the use of our oil products (Scope 3, Category 11) by 15-20% by 2030 compared with 2021 [A]. This level of ambition is in line with the EU's climate goals in the transport sector, which are among the most progressive in the world. Achieving this ambition means reducing sales of oil products compared with our 2021 baseline, as we support customers to move to electric mobility and low-carbon fuels, such as biofuels.

[A] Customer emissions from the use of our oil products (Scope 3, Category 11) were 517 million tonnes CO₂e in 2023 and 569 million tonnes CO₂e in 2021.

In the short and medium term, we have set climate targets for emissions that we are able to control, namely our Scope 1 and 2 emissions, methane emissions and flaring. We have also set climate-related targets and an ambition for emissions that are outside our control. These include our ambition to reduce the Scope 3, Category 11 customer emissions from the use of our oil products, and our target to reduce the NCI of the energy products we sell.

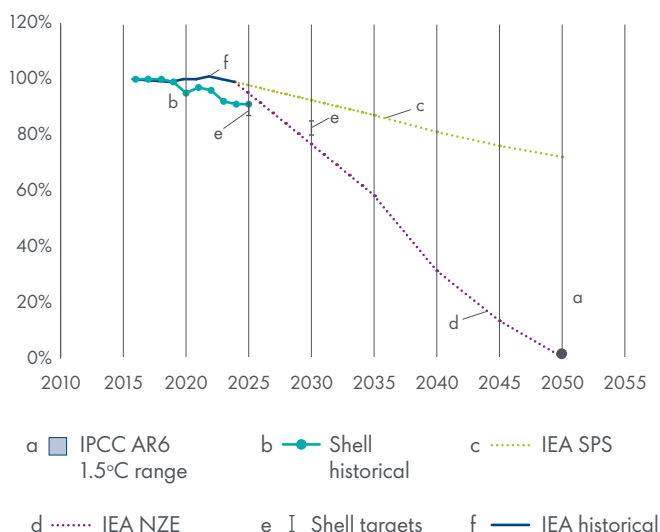
Setting targets for NCI

Shell's target is to become a net-zero emissions energy business by 2050. We also have short-, medium- and long-term targets to reduce the carbon intensity of the energy products we sell, measured using our NCI metric. We believe these targets are aligned with the more ambitious goal of the Paris Agreement, which is to limit the rise in global average temperature this century to 1.5°C above pre-industrial levels. There is no established standard for aligning an energy supplier's decarbonisation targets within this goal. For this reason, we have defined our NCI target using 1.5°C scenarios developed for the IPCC's AR6.

We start with the complete set of 1.5°C scenarios and then exclude scenarios which are too reliant on carbon removals or the use of bioenergy before removing outliers. We then calculate an emissions intensity for each scenario which is comparable to our own NCI. Finally, we produce a 1.5°C pathway based on the reductions in emissions intensity over time. We have chosen to use a range instead of any individual scenario to better reflect the uncertainty of the energy transition.

We believe that using this pathway to set our targets demonstrates that they are aligned with the more ambitious 1.5°C goal of the Paris Agreement. This is illustrated in the chart below. We also believe that the pace of change will vary around the world by region and by sector, taking into consideration the time needed for energy users to invest in large-scale equipment and the energy infrastructure changes needed for Shell to deliver more low- and zero-carbon energy.

Shell's NCI targets



Progress towards our Scope 1 and 2 target

The chart below shows our progress since 2016 in reducing our Scope 1 and 2 emissions and gives an indication of how we expect to achieve our target in 2030. The actions we take to achieve our target will depend on the evolution of our asset portfolio and the continued development of technologies which reduce carbon emissions. We expect that, on a net portfolio basis, reductions predominantly from abatement projects, including CCS and electrification, may outweigh increases in our Scope 1 and 2 emissions from new investments between 2025 and 2030. Our investments in producing low-carbon energy will increase our Scope 1 and 2 emissions, while reducing the NCI of the products we sell. Subsequent reductions in our emissions are reflected in the mechanisms outlined below and reflect an expected path to meeting our target by 2030.

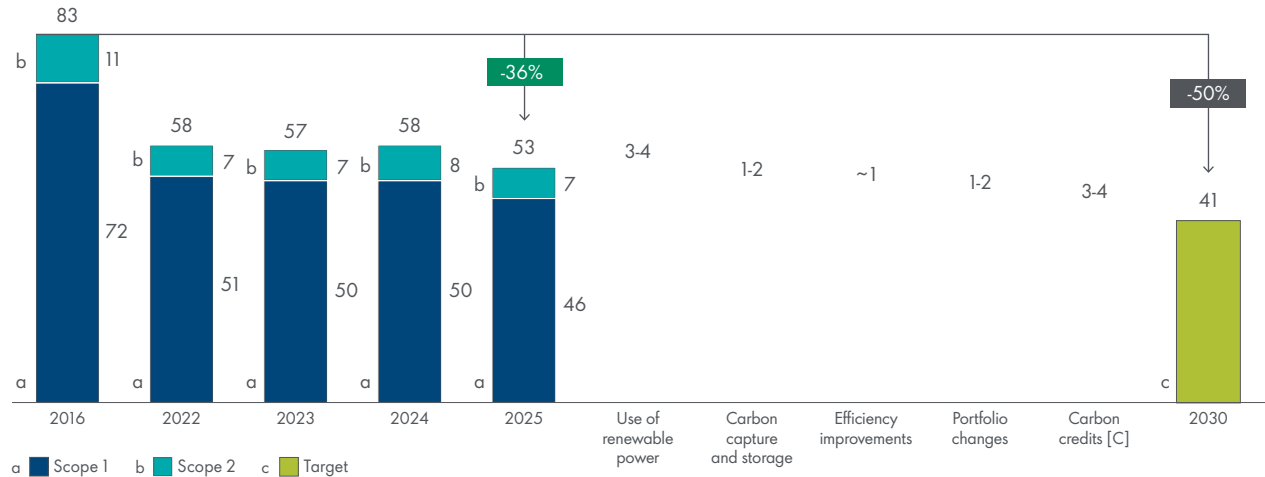
To decarbonise our operations, we are focusing on:

- using more renewable electricity to power our operations;
- developing CCS for some of our facilities;
- improving the energy efficiency of our operations; and
- making portfolio changes such as acquisitions and investments in low-carbon intensity projects, decommissioning facilities and divesting assets, while sustaining our oil production.

If required, we may choose to use high-quality carbon credits to offset any remaining emissions from our operations, in line with the carbon mitigation hierarchy of avoid, reduce and compensate.

Working to reduce our absolute Scope 1 and 2 emissions

Scope 1 and 2 emissions in million tonnes CO₂e [A] [B]



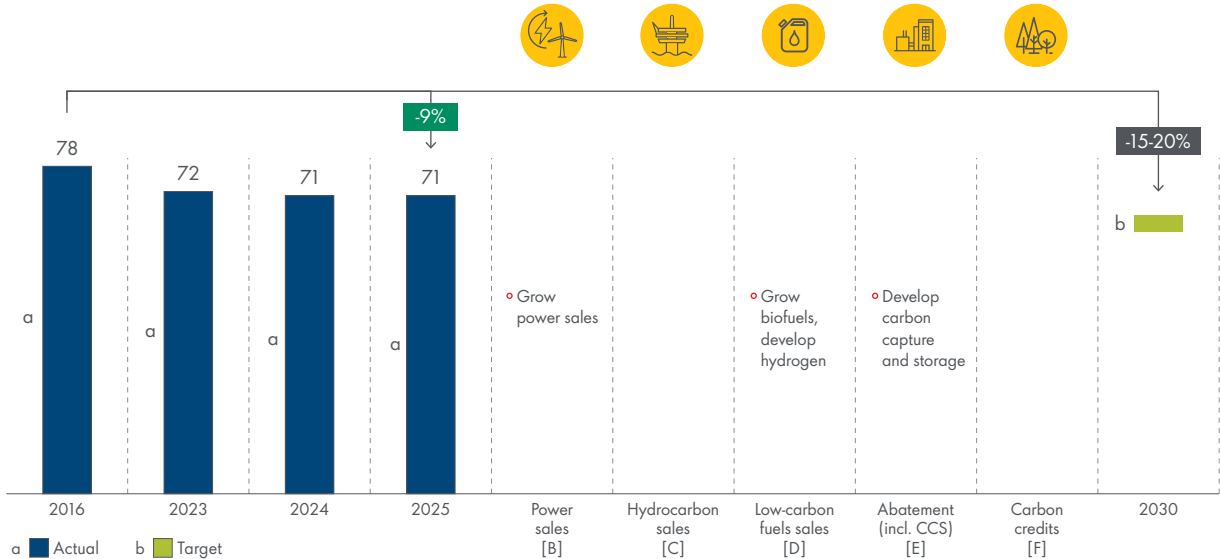
[A] The 2016 baseline may be recalculated if an acquisition or a divestment has an impact of more than 10% on total Scope 1 and 2 emissions.
[B] Operational control boundary and presented on a net basis (i.e. inclusive of any use of carbon credits).
[C] Including compliance and voluntary carbon credits as required.

Progress towards our NCI target

Unlike Scope 1 and 2 emissions, reducing the NCI of the products we sell requires action by both Shell and our customers, with the support of governments and policymakers to create the right conditions for change. The biggest driver for reducing our NCI is increasing the sales of and demand for low-carbon energy. The chart below illustrates how changes in the volume of products and services we sell could result in NCI reductions towards 2030. The change in our sales of these products and services will also reflect the development and adoption of new technologies and infrastructure, and the adoption of public policies designed to encourage the energy transition.

Working to reduce our NCI

NCI in gCO₂e/MJ [A]



[A] Grams of carbon dioxide equivalent per megajoule.
[B] Expected growth of our integrated power business and increasing sales of renewable power.
[C] Effect of proportionally lower sales of oil products and higher sales of natural gas and LNG. Emissions associated with gas and LNG are lower than those of oil products.
[D] Sales of low-carbon fuels, such as biofuels, and development of hydrogen.
[E] CCS reduces carbon emissions by capturing them at source.
[F] Can be used to offset remaining carbon emissions, particularly in hard-to-abate sectors such as aviation and industries including cement and steel.

Linking Shell's emissions targets to remuneration

We have established remuneration structures to support us in reducing our operational emissions and to support customers in reducing their emissions. The majority of employees participate in the discretionary annual bonus arrangements, which are based on the Group scorecard. Our annual bonus scorecard and Performance Share Awards (PSA) include "Shell's journey in the energy transition" performance metrics, which are designed to align with Shell's Operating Plan and longer-term strategic ambitions.

PSA will be awarded to Executive Directors and around 3,000 other employees across the Group.

See "Directors' Remuneration Report" on pages 176-182.

Energy transition performance condition and the vesting of the 2023 LTIP and PSP awards

For 2023 share awards, assessment of performance is based on Net Carbon Intensity (NCI) reduction against the 2016 base year and supporting strategic themes of reducing Scope 1 and 2 emissions; building a renewable power business; growing new low-carbon energy offerings; and developing emission sinks and offsets. Overall, it was determined that the energy transition performance condition (accounting for 25% of the LTIP award and 12.5% of the PSP award) should vest at 120% of target. See "2023 share award energy transition performance condition: outcome" on pages 189-191 for more information.

See "Annual Report on Remuneration" on pages 183-199.

Energy transition performance condition in the 2025 PSA

For the 2025 PSA, the Shell's journey in the energy transition performance condition had a weighting of 25%. Determination of the extent to which awards will vest will be based on its holistic assessment of progress towards reducing emissions from our operations and supporting our customers to reduce their emissions.

Energy transition performance condition for 2026 PSA

For the 2026 PSA, the Shell's journey in the energy transition performance condition has a weighting of 20% and retains the same performance assessment framework as for 2025. The REMCO's determination of the vesting outcome will be based on its holistic assessment of progress towards reducing emissions from our operations and supporting our customers to reduce their emissions. This will be based on our climate-related targets for our own operations as follows:

- halving Scope 1 and 2 emissions by 2030 under operational control on a net basis (2016 baseline); and
- maintaining methane emissions intensity below 0.2% and achieving near-zero methane emissions intensity by 2030.

The REMCO will also take account of progress in developments that support the energy transition to 2030 and beyond, such as the development of our Power business (including renewables), lower carbon intensity LNG production using, for example, CCS and renewable power, and low-carbon solutions, such as biofuels, electric vehicle charging, hydrogen and CCS. The REMCO will take into account progress towards achieving a 15-20% reduction in NCI by 2030 (2016 baseline), a 15-20% reduction in customer emissions from the use of our oil products by 2030 (2021 baseline) [A], as well as Shell's wider performance in accelerating the energy transition, e.g. demonstrating leadership and advocacy in standard setting, alongside any other factors that the REMCO considers relevant.

[A] This ambition was set in March 2024. Customer emissions from the use of our oil products (Scope 3, Category 11) were 517 million tonnes CO₂e in 2023 and 569 million tonnes CO₂e in 2021.

See "Annual Report on Remuneration" on page 198 for more information on the proposed performance framework.

Climate-related targets in the annual bonus scorecard

Delivering on our climate-related targets and ambition is part of the annual bonus scorecard, which helps determine annual performance bonus outcomes for senior management and the majority of Shell's employees.

The measures included in the annual bonus scorecard are shown in the table below.

2025 scorecard: Shell's journey in the energy transition

		2025 Target	2025 Performance	2025 Status
LNG volumes [A]	million tonnes per annum	27.5	28.4	Above target
Reducing operational emissions	thousand tonnes of CO ₂ e	1,050	1,238	Above target
Supporting customer decarbonisation [B]	Number of EV charge points	80,000	83,493	Above target

[A] Equity liquefaction.
[B] For the purpose of the scorecard, the number of electric vehicle (EV) charge points in the supporting customer decarbonisation metric was adjusted to exclude 4,407 electric vehicle charge points divested effective January 2, 2026

The Shell's journey in the energy transition metric reflects progress on our longer-term strategic ambitions. The overall score was above target for the year.

LNG volumes [B]: Performance is measured based on liquefaction volumes. Our score for LNG liquefaction volumes in 2025 reflects strong operational performance across most Integrated Gas assets and a maintenance programme with no major delays.

[B] Equity liquefaction.

Reducing operational emissions: We achieved a significant reduction in operational emissions from abatement, renewable energy, and permanent shutdowns or conversions ("right-sizing"). The main contributors were multiple transformation projects in Rheinland in Germany (Chemicals and Products), compressor electrification in Canada (Integrated Gas) and catalyst improvements in Qatar (Integrated Gas).

Supporting customer decarbonisation: We have continued to expand our network of electric vehicle charge points, mainly driven by growth in China and Ubitricity's portfolio. The business is focused on building a leaner, more profitable e-Mobility network to deliver long-term success.

2026 scorecard: Shell's journey in the energy transition

Given the evolution of the business, and the shift in focus to value over volume, the supporting customer decarbonisation metric will move from assessing the number of electric vehicle charge points to electric vehicle charging gross margin growth.

See "Annual Report on Remuneration" on page 187.