

Global Energy and Climate Model

Documentation - 2024



International
Energy Agency

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Overview of model and scenarios

Since 1993, the IEA has provided medium- to long-term energy projections using a continually evolving set of detailed, world-leading modelling tools. First, the World Energy Model (WEM) – a large-scale simulation model designed to replicate how energy markets function – was developed. A decade later, the Energy Technology Perspectives (ETP) model – a technology-rich bottom-up model – was developed for use in parallel to the WEM. In 2021, the IEA adopted a new hybrid modelling approach relying on the strengths of both models to develop the world's first comprehensive study of how to transition to an energy system at net zero CO₂ emissions by 2050.

Over the past three years, the IEA has worked to develop a new integrated modelling framework: the IEA's Global Energy and Climate (GEC) Model. This model is now the principal tool used to generate detailed sector-by-sector and region-by-region long-term scenarios across IEA's publications.

The GEC Model brings together the unique modelling capabilities of the WEM and ETP models. The result is a large-scale, bottom-up partial-optimisation modelling framework allowing for a unique set of analytical capacities in energy markets, technology trends, policy strategies and investments across the energy sector that would be critical to achieve climate goals. The IEA's GEC Model covers 27 regions that can be aggregated to world-level results, and covers all sectors across the energy system with dedicated bottom-up modelling for:

- **Final energy demand**, covering industry, transport, buildings, agriculture and other non-energy use. This is driven by detailed modelling of energy service and material demand.
- **Energy transformation**, including electricity generation and heat production, refineries, the production of biofuels, hydrogen and hydrogen-based fuels and other energy-related processes, as well as related transmission and distribution systems, storage and trade.
- **Energy supply**, including fossil fuels exploration, extraction and trade, and the availability of renewable energy resources.

The GEC Model is a highly data-intensive model covering the whole global energy system. Much of the data on energy supply, transformation and demand, as well as energy prices, is obtained from the IEA's own databases of energy and economic statistics (IEA, 2024a). It also draws on data from collaboration with other institutions and from a wide range of external sources, which are indicated in the relevant sections of this document. The development of the GEC Model benefited from expert review within the IEA and beyond, and the IEA continues to work closely with colleagues in the international modelling community.

The GEC Model is designed to analyse a diverse range of aspects of the energy system, including:

- **Global and regional energy prospects:** including trends in demand, supply availability and constraints, international trade and energy balances by sector and by fuel in the projection horizon.
- **Environmental impact of energy use:** including CO₂ emissions from fuel combustion, industrial processes and flaring; methane (CH₄) emissions from fossil fuel operations; CH₄ and nitrous oxide (N₂O) emissions from final energy demand and energy transformation, local air pollutants, and temperature outcomes.
- **Effects of policy actions and technological changes:** including the impact of a range of policy actions and technological developments on energy demand, supply, trade, investments and emissions.
- **Investment in the energy sector:** including investment requirements in fuel and technology supply chains to satisfy projected energy demand and demand-side investment requirements.
- **Modern energy access assessments:** including trends in access to electricity and clean cooking, as well as the related additional energy demand and investments, and changes in GHG emissions.
- **Energy employment:** including the impact of the energy sector's evolution on employment in each scenario.

1.1 GEC Model scenarios

The IEA’s medium- to long-term outlook publications – including the World Energy Outlook (WEO) and Energy Technology Perspectives (ETP) – use a scenario approach relying on the GEC Model to examine future energy trends. The GEC Model is used to explore multiple scenarios, each of which is built on a different set of underlying assumptions about how the energy system might evolve over time. By comparing them, readers can assess what drives the various outcomes, and the opportunities and pitfalls that lie along the way. These scenarios are not predictions, and do not contain a single view about what the long-term future might hold. Instead, the scenarios seek to enable readers to compare different possible versions of the future, and the levers and actions that produce them, and to gain insights into the future of global energy.

The World Energy Outlook, Energy Technology Perspectives, and their related reports explore different aspects of three scenarios, all of which are fully updated to include the latest energy market and cost data. The Stated Policies Scenario (STEPS) and the Announced Pledges Scenario (APS) are exploratory, in that they define a set of starting conditions, such as policies and targets, and see where they lead based on model representations of energy systems that reflect market dynamics and technological progress. The Net Zero Emissions by 2050 Scenario (NZE Scenario) is normative, in that it is designed to achieve specific outcomes – net zero emissions from the energy sector by 2050 without offsets from other sectors, an emissions trajectory consistent with keeping the temperature rise in 2100 below 1.5 °C (with at least a 50% probability) with limited overshoot, universal access to modern energy services by 2030 and major improvements in air quality – and shows a pathway to reach them.

Table 1.1 ► Definitions and objectives of the GEC Model 2024 scenarios

	Stated Policies Scenario (STEPS)	Announced Pledges Scenario (APS)	Net Zero Emissions by 2050 Scenario (NZE Scenario)
Definitions	A scenario which reflects current policy settings based on a sector-by-sector and country-by-country assessment of the energy-related policies that were in place by the end of August 2024, as well as those that are under development. The scenario also takes into account currently planned manufacturing capacities for clean energy technologies.	A scenario which assumes that all climate commitments made by governments and industries around the world by the end of August 2024, including Nationally Determined Contributions (NDCs) and longer-term net zero targets, as well as targets for access to electricity and clean cooking, will be met in full and on time.	A scenario which sets out a pathway for the global energy sector to achieve net zero CO ₂ emissions by 2050. It does not rely on emissions reductions from outside the energy sector to achieve its goals. Universal access to electricity and clean cooking are achieved by 2030. The scenario was updated with the latest available data in 2024.
Objectives	To provide a benchmark to assess the potential achievements (and limitations) of recent developments in energy and climate policy. The differences between the STEPS and the APS highlight the “implementation gap” that needs to be closed for countries to achieve their announced decarbonisation targets.	To show how close current pledges get the world to the target of limiting global warming to 1.5 °C. The differences between the APS and the NZE Scenario highlight the “ambition gap” that needs to be closed to achieve the goals of the Paris Agreement adopted in 2015. It also shows the gap between current targets and achieving universal energy access.	To show what is needed across the main sectors by various actors, and by when, for the world to achieve net zero energy-related and industrial process CO ₂ emissions by 2050 while meeting other energy-related sustainable development goals such as universal energy access.

The scenarios highlight the importance of government policies in determining the future of the global energy system: decisions made by governments are the main differentiating factor explaining the variations in outcomes

across our scenarios. However, we also take into account other elements and influences, notably the economic and demographic context, technology costs and learning, energy prices and affordability, corporate sustainability commitments, and social and behavioural factors. While the evolving costs of known technologies are modelled in detail, we do not try to anticipate technology breakthroughs (e.g. nuclear fusion).

An inventory of the key policy assumptions along with the underlying data on population, economic growth, resources, technology costs and fossil fuel prices is available in Chapter 2.

1.1.1 Stated Policies Scenario

The STEPS provides a more conservative benchmark for the future, by not taking for granted that governments will reach all announced goals. Instead, it provides a more granular, sector-by-sector evaluation of the policies that have been put in place to reach the stated goals of these policies and other energy-related objectives, taking account not only of existing policies and measures but also of those that are under development. The STEPS explores where the energy system might go without a major additional steer from policy makers. Similarly to the APS, it is not designed to achieve a particular outcome.

The policies assessed in the STEPS cover a broad spectrum, including NDCs under the Paris Agreement and much more. In practice, the bottom-up modelling effort in this scenario requires extensive detail at the sectoral level, including pricing policies, efficiency standards and schemes, electrification programmes and specific infrastructure projects. The scenario takes into account the relevant policies and implementation measures adopted as of the end of August 2024, as well as policy proposals, even though specific measures needed to put them into effect have yet to be fully developed.

Government announcements include some far-reaching targets, such as aspirations to achieve full energy access in a few years, to reform pricing regimes and, more recently, to reach net zero emissions. As with all the policies considered in the STEPS, these ambitions are not automatically incorporated into the scenario. Full implementation cannot be taken for granted, so the prospects and timing for their realisation are based upon our assessment of countries' relevant regulatory, market, infrastructure and financial circumstances.

Where policies are time-limited, they are generally assumed to be replaced by measures of similar intensity. We do not assume future strengthening – or weakening – of future policy action, except where there already is specific evidence to the contrary.

The STEPS takes account of industry action, including manufacturing capacity for clean energy technologies, and the impacts of this capacity on market uptake beyond policies in force or announced.

The STEPS shows that in aggregate, current country commitments are enough to make a significant difference. However, there is still a large gap between the STEPS projections and the trajectories of the APS and the NZE Scenario.

1.1.2 Announced Pledges Scenario

The APS, introduced in 2021, aims to illustrate the extent to which announced ambitions and targets are able to deliver the emissions reductions needed to achieve net zero emissions by 2050. It includes all recent major national announcements as of the end of August 2024, for both 2030 targets and longer-term net zero or carbon neutrality pledges, regardless of whether these announcements have been anchored in legislation or in updated NDCs. In the APS, countries fully implement their national targets, and the outlook for exporters of fossil fuels and low-emissions fuels such as hydrogen is shaped by what full implementation of all targets means for global demand. The APS also assumes that all country targets for access to electricity and clean cooking are achieved on time and in full.

The way these pledges are assumed to be implemented in the APS has important implications for the energy system. A net zero pledge for economy-wide GHG emissions does not necessarily mean that CO₂ emissions from the energy sector need to reach net zero. For example, a country's net zero plans may envisage that some remaining energy-related emissions are offset by the absorption of emissions from forestry or land use. It is not possible to know exactly how net zero pledges will be implemented, but the design of the APS, particularly with respect to the details of the energy system pathway, has been informed by the pathways that a number of national bodies have developed to support net zero pledges. For countries that have not yet made a net zero pledge, policies are assumed to be the same as in the STEPS. Non-policy assumptions, including population and economic growth, are the same as in the STEPS.

1.1.3 Net Zero Emissions by 2050 Scenario

The NZE Scenario is a normative scenario that shows a pathway for the global energy sector to achieve net zero CO₂ emissions by 2050, with advanced economies reaching net zero emissions in advance of others. This scenario also meets key energy-related Sustainable Development Goals (SDGs), in particular universal energy access by 2030 and major improvements in air quality. It is consistent with limiting the global temperature rise to 1.5 °C (with at least a 50% probability) with limited overshoot, in line with reductions assessed in the Intergovernmental Panel on Climate Change (IPCC)'s Sixth Assessment Report.

There are many possible paths to achieve net zero CO₂ emissions globally by 2050 and many uncertainties that could affect any of those pathways; the NZE Scenario is therefore *a* path, and not *the* path to net zero emissions.

The Net Zero Emissions by 2050 Scenario:

- Describes a pathway for the global energy sector to reach net zero emissions of CO₂ by 2050 by deploying a wide portfolio of clean energy technologies, without offsets from land-use measures, and with decisions about technology deployment driven by costs, technology maturity, market conditions, available infrastructure and policy preferences.
- Recognises that achieving net zero energy sector CO₂ emissions by 2050 depends on fair and effective global co-operation. The pathway to net zero emissions by 2050 is very narrow. All countries will need to contribute to deliver the desired outcomes; advanced economies take the lead and reach net zero emissions earlier in the NZE Scenario than emerging market and developing economies. Global access to electricity and clean cooking is achieved by 2030 in line with established SDGs. Rapid and major reductions in methane emissions from the oil, gas and coal sectors help to buy some time for less abrupt CO₂ reductions in emerging market and developing economies. Global collaboration facilitates the development and adoption of ambitious policies, drives down clean technology costs, and scales up diverse and resilient global supply chains for critical minerals and clean energy technologies. Enhanced financial support to emerging market and developing economies plays a critical part in this collaboration.
- Prioritises an orderly transition that aims to safeguard energy security through strong and co-ordinated policies and incentives that enable all actors to anticipate the rapid changes required, and to minimise energy market volatility and stranded assets. The scenario is underpinned by detailed analysis of project lead times for minerals supplies and clean energy technologies as part of efforts to ensure the feasibility of the deployment.

In recent years, the energy sector was responsible for around three-quarters of global GHG emissions. Achieving net zero energy-related and industrial process CO₂ emissions by 2050 in the NZE Scenario does not rely on action beyond the energy sector, but limiting climate change does require such action. We therefore additionally examine the reductions in CO₂ emissions from land use that would be commensurate with the transformation of the energy sector in the NZE Scenario, working in co-operation with the International Institute for Applied Systems Analysis (IIASA).

Box 1.1 ▶ An integrated approach to energy and sustainable development in the Net Zero Emissions by 2050 Scenario

The Net Zero Emissions by 2050 Scenario (NZE Scenario) integrates three key objectives of the United Nations (UN) 2030 Agenda for Sustainable Development: universal access to modern energy services by 2030 (SDG 7.1), reducing health impacts of air pollution (SDG 3.9), and action to tackle climate change (SDG 13).

As a first step, we use the GEC Model to assess how the energy sector would need to change to deliver **universal access to modern energy services by 2030**. To analyse electricity access, we combine cost-optimisation with new geospatial analysis that considers current and planned transmission lines, population density, resource availability and fuel costs. Second, we consider ambient and household **air pollution** and **climate goals**.

The policies needed to achieve the SDGs covered in the NZE Scenario are often complementary. For example, energy efficiency and renewable energy significantly reduce local air pollution, particularly in cities. Access to clean cooking reduces indoor air pollution and yields a net reduction in GHG emissions (by reducing emissions from the incomplete combustion of biomass as well as by reducing deforestation). However, trade-offs also exist. For example, electric vehicles reduce local air pollution from traffic, but can increase overall CO₂ emissions if there is not a parallel effort to decarbonise the power sector. Ultimately, the balance of potential synergies or trade-offs depends on the route chosen to achieve the energy transition, making an integrated, whole-system approach to scenario building essential. The emphasis of the NZE Scenario is on technologies with short project lead times in the power sector in particular, such as renewables, but given the long-term nature of climate change, other technology choices will come into play in the future. Modern use of biomass as a decarbonisation option is also less relevant in the NZE Scenario than in a single-objective climate scenario, because biomass is a combustible fuel, requiring post-combustion control to limit air pollutant emissions, making it more costly than its alternatives in certain regions.

The NZE Scenario also looks at the implications for the energy sector of achieving targets under SDG 6 (**clean water and sanitation for all**) and what policy makers need to do to achieve multiple goals with an integrated and coherent policy approach.

The time horizon of the model is 2050, to enable us to reflect in our modelling the announcements made by several countries to achieve carbon neutrality by 2050, and the potential for new technologies (such as hydrogen and renewable gases) to be deployed at scale. The interpretation of the climate target embodied in the NZE Scenario also changes over time, as a consequence of both ongoing GHG emissions as well as developments in climate science (refer to Section 8 on emissions for more detail).

1.2 Selected developments in 2024

The primary sectoral and topic-specific model developments undertaken this year include the following:

Cross-cutting

Manufacturing and trade

- **Industry:** For steel, aluminium and ammonia, a more granular methodology for projecting demand and new modelling of trade flows has been developed and coupled with demand and production projections in the GEC Model. Full details on the IEA's new Manufacturing and Trade Model are included in the forthcoming 2024 edition of *Energy Technology Perspectives 2024* (IEA, 2024b).
- **Transport:** A new bottom-up model for shipping activity was developed to enable full consistency of shipping activity with energy, material and clean technology trade projections in IEA scenarios. For more

information on the intersection between different components of trade flows and maritime activity and routes, please see the forthcoming *ETP-24*.

Sensitivity analyses

- A suite of sensitivities were introduced to explore uncertainties in the outlook. The set of sensitivity cases investigates how outputs could diverge from the STEPS results. The cases do not change the broad policy backdrop that underpins the STEPS, nor the economic and demographic assumptions that are reflected in the STEPS. Rather, they assess how varying some of the assumptions about deployment rates might affect the outlook for energy demand by fuel, sector and region.
- Each uncertainty is explored through the framework of the GEC Model, which allows to quantify impacts, and to combine different impacts to provide a better understanding of a plausible range of outcomes for demand by energy source, type and associated CO₂ emissions. When carrying out these sensitivity analyses, we consider the implications of each uncertainty for all fuels. Analyses focus on direct impacts and avoid making assumptions about consequential synergistic or counterbalancing effects in other areas of service demand.

Policies

- The policies used to inform the GEC Model are now fully available online in the Policies and Measures Database (IEA, 2024c), which provides comprehensive information on the latest status of current policies worldwide and analysed in the Energy Policy Inventory.

Final energy consumption

Industry

- The representation of different recycling processes for plastics and paper products has been improved. For example, in the chemical industry, the refined methodology takes a deeper look into the plastic waste available, and the recycling potential based on the type of plastic and the technological readiness of recycling processes, and also distinguishes between chemical and mechanical recycling technologies. This detailed representation of energy consumption, emissions and the consequent impact on primary production provides a more nuanced understanding of the recycling landscape.
- For steel, cement and aluminium, levelised cost of production modelling has been updated with new parameters and more granularity at the process route level. Levelised cost modelling for light industries for the selection of heating options has been updated.
- Activity projections for light industries have been updated to include more bottom-up signals from clean technology manufacturing and critical mineral mining, improving coherence of scenarios at the energy system level.

Transport

- For the road module, the methodology used to project ownership of passenger light-duty vehicles, two- and three-wheelers and buses has been updated, incorporating a curve-fitting approach and factoring in rail activity trends.
- Modelling of the activity shift from passenger light-duty vehicles to buses was improved by incorporating regional-level fuel price elasticity projections.
- Update of “test cycle” to “on-road conditions” fuel economy gap factors using On-Board Fuel Consumption Meter (OBFCM) data reported by (European Commission, 2024). Update of utilisation factors (UF, the ratio of full electric mode in total driven distance) of plug-in hybrid electric vehicles (PHEVs) using real PHEV fleet measurements (ICCT, 2022).

- Implementation of a method to account for second-hand vehicle flows that assesses the impact of policies on fuel economy improvements in countries importing vehicles from regions with ambitious fuel economy goals.
- The granularity of the shipping model was considerably increased, and now includes more ship types and detailed fleet characteristics such as age, size and speed. This was possible through the integration of new data sources such as the UN Automatic Identification System (AIS) and Ship Register databases, and alignment with the latest International Maritime Organization (IMO) publications. The shipping model was extended to allow for retrofitting of existing ships with energy efficiency technologies and alternative methods of propulsion. A total cost of ownership tool for ships was developed and coupled with the shipping model to inform fuel shares and penetration of energy efficiency technologies in new ships and retrofits.

Buildings

- Modelling of space heating and space cooling technologies has been improved to reflect differences by building type, depending on their respective insulation levels and compliance with net zero standards. This added granularity allows the model to reflect targeted policies with different technology options per building type, and captures the impact of insulation on the operation of the technology.
- Updated modelling assumptions on building retrofit rates have been incorporated, along with improved assessment of associated energy savings and costs.
- Energy demand from data centres is now itemised separately in the model as part of ongoing improvements in this rapidly developing area. Data centres' electricity consumption is classified under the services sector, following the International Standard Industrial Classification of All Economic Activities (ISIC), and is further divided into cooling, appliances, and auxiliary equipment.

Hourly electricity demand

- The granularity of end uses covered by the hourly electricity demand model has been increased: space heating and cooling has been split by building type and technology, and road transport was split by charging location and charger capacity. The model can accommodate different load patterns for some technologies, such as heat pumps or fast-chargers for EVs.
- Electricity consumption for district heating has been included as a dedicated category, reflecting the underlying uses of distributed heat in buildings and industry and the respective load variations with outdoor temperature.

Behavioural change analysis

- The modelling of behavioural changes in the APS has been improved to reflect the level of quantification of behavioural levers in NDCs and long-term strategies, and whether enabling features (such as planned public infrastructure or intended policy support) are in place.

Electricity generation

- The battery storage model has been expanded to include behind-the-meter applications, in addition to utility-scale batteries.

Energy supply

- Liquefied natural gas (LNG) flows within the trade regions of the natural gas model (i.e. intra-regional LNG trade) have been added.

Hydrogen

- Liquid organic hydrogen carrier (LOHC), specifically methylcyclohexane made with hydrogen and toluene, has been added as a shipping option for hydrogen trade. This includes the dehydration process to reconvert the LOHC back into hydrogen at the destination.

Critical minerals

- A new module to project the supply for six focus critical minerals based on announced project pipelines for mining and refining was added to the GEC Model. Primary supply requirements have been assessed by deducing projected secondary supply from projected total demand.
- The mineral recycling model was integrated into the broader model for the demand and supply of critical minerals. For the non-energy sectors, secondary mineral supply projections are based on historical trends for secondary supply in the sector, assuming gradual improvement in collection rates and efficiency levels by scenario. For clean energy applications, there is an enhanced granularity by sector, assessing lifetime by technology (for example, solar PV, wind turbines and EVs), collection and yield rates by application and mineral, based on an extensive literature review.

Decomposition

- Expansion of the granularity of fuels considered for shipping (international and domestic) allowing for a more detailed assessment of the role of biomethanol and synthetic methanol in the decomposition analytical outputs.
- A higher level of detail was added to the residential sector, with space heating and space cooling technologies reflecting different building types, allowing for a refined assessment of the efficiency lever in the decomposition outputs.

Household energy expenditure

- A new analysis was developed to assess household energy expenditures and the proportion of these costs relative to household disposable income, broken down by income bracket.

1.3 GEC Model overview

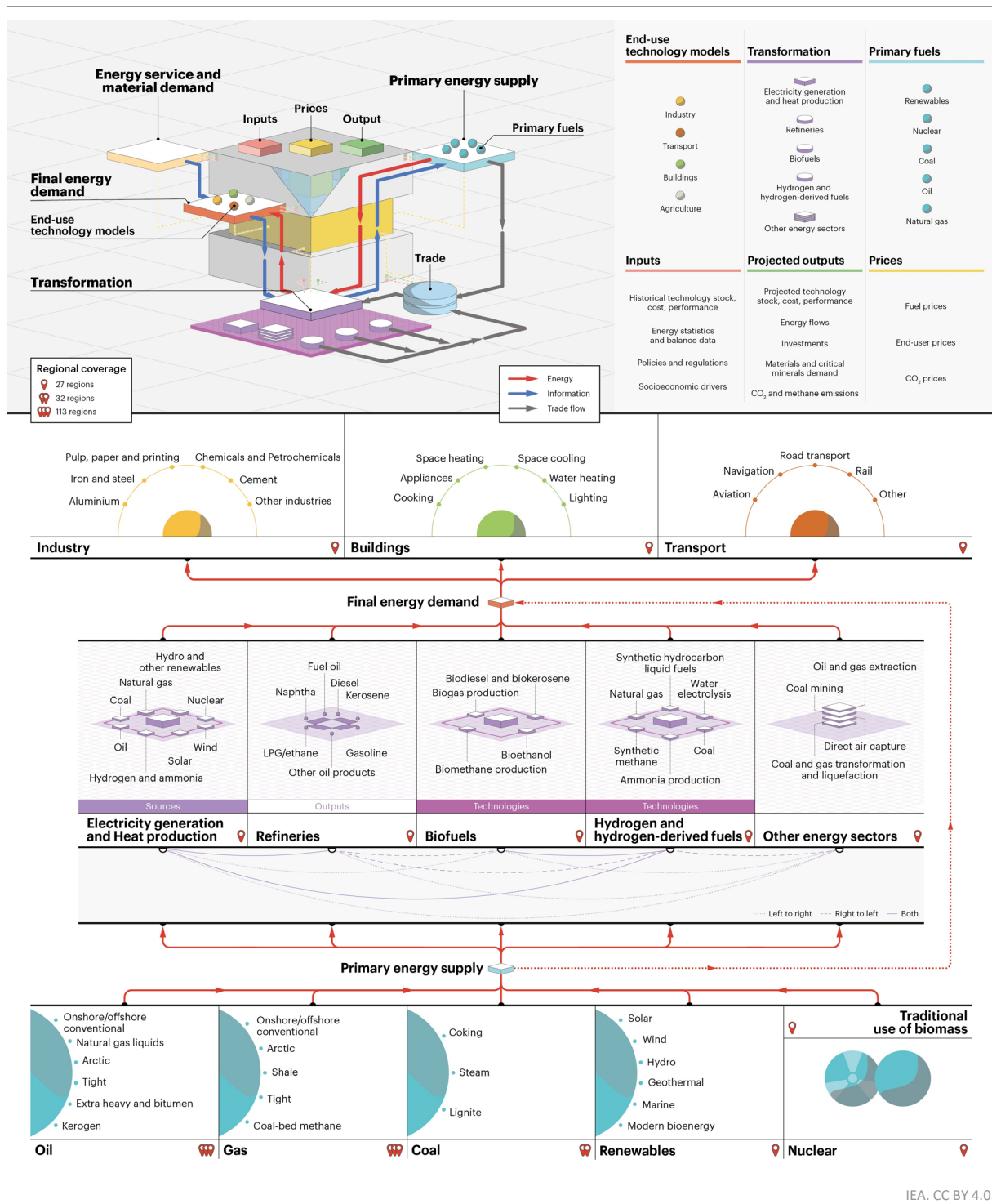
1.3.1 Modelling methodology

The GEC Model is a bottom-up partial-optimisation model covering energy demand, energy transformation and energy supply (Figure 1.1). The model uses a partial equilibrium approach, integrating price sensitivities. It shows the transformation of primary energy along energy supply chains to meet energy service demand, the final energy consumed by the end-user. The supply, transformation and demand modules of the model are dynamically soft-linked: consumption of electricity, hydrogen and hydrogen-related fuels, biofuels, oil products, coal and natural gas in the end-use sector model drives the transformation and supply modules, which in turn feed energy prices back to the demand module in an iterative process. In addition, energy system CO₂, methane (CH₄) and nitrous oxide (N₂O) emissions are assessed. The model also comprises additional modules evaluating system implications such as investments, critical minerals, employment, temperature outcomes, land use, and air pollution.

The main exogenous drivers of the scenarios are economic growth, demographic change, and technological developments. Energy service demand drivers, such as steel demand in industry or the number of appliances owned by each household, are estimated econometrically based on historical data and on the socio-economic drivers. Interactions between energy service demand drivers are also accounted for, such as the influence of the number of vehicle sales on materials demand.

This service demand is met by existing and new technologies. All sector modules (see subsequent sections for more details on these modules) base their projections on the existing stock of energy infrastructure (e.g. the production capacity in industry, floorspace in buildings, number of vehicles in transport), through detailed stock-accounting frameworks. To assess how service demand is met in the various scenarios, the model includes a wide range of fuels and technologies (existing and additions). This includes careful accounting of the current energy performance of different technologies and processes, and the potential for energy efficiency improvements.

Figure 1.1 ▶ Global Energy and Climate Model overview



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The sectoral energy and emission balances are calculated based on the final energy end uses – the service demand – by determining first the final energy demand needed to serve it, then the required transformations to convert primary energy into the required fuels, and finally the primary energy needs. This is based on a partial equilibrium approach using for some elements a partial-optimisation model, within which specific costs play an important role in determining the share of fuels and technologies to satisfy energy service demand. In different parts of the model, logit and Weibull functions are used to determine the share of technologies based upon their specific costs. This includes investment costs, operating and maintenance costs, fuel costs and in some cases costs for emitting CO₂. In certain sectors, such as hydrogen production, specially designed and linked optimisation modules are used.

While the model aims to identify an economical way for society to reach the desired scenario outcomes, the results do not necessarily reflect the least-cost pathway. This is because an unconstrained least-cost approach may fail to take account of all the issues that need to be considered in practice, such as market failures, political or individual preferences, feasible ramp-up rates, capital constraints and public acceptance. Instead, the analysis pursues a portfolio of fuels and technologies within a framework of cost minimisation, considering technical, economic and regulatory constraints. This approach, tailored to each sector and incorporating extensive expert consultation, enables the model to reflect as accurately as possible the realities of different sectors. It also offers a hedge against the real risks associated with the pathways: if one technology or fuel fails to fulfil its expected potential, it can more easily be compensated by another if its share in the overall energy mix is low.

All fuels and technologies included in the model are either already commercially available or at a relatively advanced stage of development, and therefore have at least reached a prototype size from which enough information about expected performance and costs at scale can be derived. Costs for new clean fuels and technologies are expected to fall over time and are informed in many cases by learning curve approaches, helping to make a net zero future economically feasible.

Besides this main feedback loop between supply and demand, there are also linkages between the transformation and supply modules, and further linkages such as material flows or biogenic or atmospheric CO₂ via direct air capture (DAC) for synthetic fuel production. Primary energy needs and availability interact with the supply module. Complete energy balances are compiled at a regional level and the CO₂ emissions of each region are then calculated using derived CO₂ factors, taking into account reductions from CO₂ removal technologies.

The GEC Model is implemented in the simulation software Vensim (Ventana Systems Inc., 2024), but makes use of a wider range of software tools, including TIMES (IEA-ETSAP, 2024).

1.3.2 Data inputs

The GEC Model is a data-intensive model covering the whole global energy system. Much of the data on historical energy supply, transformation and demand, as well as energy prices, is obtained from the IEA's own energy and economic data. Additional data from a wide range of often sector-specific external sources is also used, in particular to establish the historical size and performance of energy-consuming stocks.

The model is recalibrated annually to the latest available data. The formal base year for this year's projections is 2022, as this is the most recent year for which a full energy balance by country is available. However, we have used more recent data wherever available, and including 2023 and 2024 estimates for energy production and demand. Estimates for the year 2023 are based on the IEA's *CO₂ Emissions in 2023* report, in which data are derived from a number of sources, including the latest monthly data submissions to the IEA Energy Data Centre, other statistical releases from national administrations, and recent market data from the IEA *Market Report Series* that cover coal, oil, natural gas, renewables and electricity. Investment estimates include data for the year 2024, based on the IEA *World Energy Investment 2024* report. Data on deployment and techno-economic performance of technologies used in different sector models include 2023 and estimates for 2024, such as data

in *Tracking Clean Energy Progress 2023*, the *Global Hydrogen Review 2024*, and the *Global Electric Vehicle Outlook 2024*.

For a summary of selected key data inputs – including macro drivers such as population, economic developments and prices as well as techno-economic inputs such as fossil fuel resources and technology costs – please see the GEC Model key input dataset (IEA, 2024d).

1.3.3 Regional coverage and time horizon

The GEC Model covers the energy developments in the full global energy system up to 2050, with the capacity to extend beyond 2050 for some regions. Simulations are carried out on an annual basis, with hourly modelling for the power sector. The current version of the model provides results for 27 regions of the globe, of which 13 are individual countries. Several supply components of the model have further regional disaggregation: the oil and gas supply model has 113 regions and the coal supply model 32 regions.

1.3.4 Capabilities and features

The IEA's GEC Model offers unparalleled scope and detail about the energy system. Its essential purpose is evaluating energy supply and demand, as well as the environmental impacts of energy use and the impacts of policy and technology developments on the energy system. Through long-term scenario analysis, the model enables analysis of possible futures related to the following main areas:

- **Global and regional energy trends:** Assessment of energy demand, supply availability and constraints, international trade and energy balances by sector and by fuel.
- **Environmental impact of energy use:** CO₂ emissions from fuel combustion are derived from the projections of energy consumption. CO₂ process emissions are based on the production of industrial materials and CH₄ and N₂O emissions are assessed for final energy demand as well as for energy transformation. Methane from oil and gas operations is assessed through bottom-up estimates and direct emissions measurements (see Methane Tracker). Local air pollutants are also estimated linking the GEC Model with the GAINS model of IIASA and the temperature outcomes of modelled scenarios are assessed using the Model for the Assessment of Greenhouse Gas Induced Climate Change (MAGICC).
- **Policy and technology developments:** the impact of policy actions and technological developments on energy demand, supply, trade, investments and emissions can be investigated by comparing between scenarios.

Additionally, the GEC Model has multiple detailed features that either underlie or build from the analysis of broader energy trends. These include:

- **Technologies:** Detailed techno-economic characterisation of more than 800 clean energy technologies, including those still under development (either at prototype or demonstration stage) for different applications in heavy industries, long-distance transport and carbon dioxide removal technologies among other sectors.
- **People-centred transitions:** Detailed modelling of behavioural changes, energy sector employment, equity outcomes and energy affordability, among other implications for citizens.
- **Critical minerals:** Comprehensive analysis of projected demand and supply of critical minerals needed for the energy sector's transition.
- **Infrastructure:** Detailed modelling and analysis of energy infrastructure development needs and strategies including electricity systems, fossil fuels, hydrogen-related fuels distribution and CO₂ transport options.
- **Variable renewables potential:** Detailed geospatial analysis of variable renewables potentials across the globe and modelling of the impact of exploiting them for hydrogen production.

- **Modern energy access:** Comprehensive modelling of the implications of and opportunities for providing energy access to all communities. This includes access to electricity and clean cooking facilities, and an evaluation of additional energy demand, investments and related GHG emissions.
- **Material efficiency:** Granular modelling of strategies along supply chains to make the use of materials including steel, cement, aluminium, plastics and fertilisers more efficient.
- **Investments:** Detailed modelling of overall energy sector and clean energy investments by sub-sector and technology areas, and comprehensive analysis on effective financing strategies. This includes investment requirements in fuel supply chains to satisfy projected energy demand and for demand-side technologies and measures (e.g. energy efficiency, electrification). Government spending is also tracked.
- **Decomposition:** Detailed mathematical framework to systematically analyse the specific contribution of different strategies to emissions or energy savings between scenarios and over time.

1.3.5 Connections with the international energy modelling community

The development of the GEC Model benefits from expert review within the IEA and beyond, and the IEA works closely with colleagues in the global modelling community. For example, the IEA participates in and regularly hosts the International Energy Workshop, and regularly interacts with the Integrated Assessment Modelling Consortium. The initial Net Zero Emissions by 2050 Scenario in 2021 was informed by discussions with modelling teams from across the world, including from China, the European Union, Japan, the United Kingdom, the United States, and the IPCC.

The IEA also has a long-standing history of working with researchers and modellers around the world as part of its Technology Collaboration Programmes (TCP) network. The TCPs support the work of independent, international groups of experts that enable governments and industries from around the world to lead programmes and projects on a wide range of energy technologies and related issues. The Energy Technology Systems Analysis Programme (ETSAP) TCP, established in 1977, is among the longest-running TCPs. The ETSAP TCP supports policy makers in improving the evidence base underpinning energy and environmental policy decisions through energy systems modelling tools including the TIMES modelling platform, and brings together a unique network of nearly 200 energy modelling teams from approximately 70 countries.

IEA's GEC Model also interacts closely with other internationally recognised models:

- The IEA uses the **Model for the Assessment of Greenhouse Gas Induced Climate Change (MAGICC)**, developed and maintained by ClimateResource and often used by the IPCC for key publications to inform its analysis of the impact of different greenhouse gas budgets on the average global temperature rise.
- IEA modelling results are coupled with the **Greenhouse Gas – Air Pollution Interactions and Synergies (GAINS)** model developed and maintained by IIASA. This allows for detailed analysis on the impact on air pollution of different IEA scenarios.
- IEA results are coupled with the **Global Biosphere Management Model (GLOBIOM)** developed and maintained by IIASA to complement the IEA's analysis on bioenergy supplies and effective use strategies.
- The **Aviation Integrated Model (AIM)** developed by University College London forms the basis for our modelling of the aviation sector.
- IEA modelling results have been linked to the **Global Integrated Monetary and Fiscal (GIMF)** model of the International Monetary Fund (IMF) to assess the impacts of changes in investment spending on global GDP.
- The **Open Source Spatial Electrification Tool (OnSSET)**, a GIS-based optimisation tool developed as a result of a collaboration among several organisations, is used to inform the IEA's energy access modelling.

Cross-cutting inputs and assumptions

The GEC Model uses macro drivers, techno-economic inputs and policies as input data to design and calculate the scenarios.

Economic activity and population are the two fundamental drivers of demand for energy services in GEC Model scenarios. Unless otherwise specified, these are kept constant across all scenarios as a means of providing a starting point for the analysis and facilitating the interpretation of the results. Energy prices are another important input.

The projections consider the average retail prices of each fuel used in final uses, power generation and other transformation sectors. These end-use prices are derived from projected international prices of fossil fuels and subsidy/tax levels and vary by country.

2.1 Population assumptions

Table 2.1 ▶ Population assumptions by region

	Compound average annual growth rate (%)				Population (million)				Urbanisation (share of population, %)			
	2000-2023	2023-2030	2023-2035	2023-2050	2023	2030	2035	2050	2023	2030	2035	2050
North America	0.9	0.6	0.5	0.4	509	529	542	566	83	84	86	89
United States	0.7	0.5	0.5	0.4	338	350	358	373	83	85	86	89
C & S America	1.0	0.7	0.6	0.5	532	559	574	601	82	83	85	88
Brazil	0.9	0.5	0.4	0.2	216	224	228	231	88	89	90	92
Europe	0.3	0.0	0.0	-0.1	691	693	692	679	76	78	80	84
European Union	0.2	-0.2	-0.2	-0.2	449	444	441	425	76	78	79	84
Africa	2.5	2.3	2.2	2.0	1 458	1 708	1 897	2 482	45	48	51	59
Middle East	2.1	1.4	1.3	1.1	269	297	315	364	73	75	76	81
Eurasia	0.4	0.3	0.2	0.2	240	244	247	255	65	67	68	73
Russia	-0.1	-0.3	-0.3	-0.3	143	140	138	132	75	77	79	83
Asia Pacific	1.0	0.5	0.5	0.3	4 319	4 489	4 584	4 734	51	55	57	64
China	0.5	-0.1	-0.2	-0.3	1 419	1 409	1 393	1 307	65	71	74	80
India	1.3	0.8	0.8	0.6	1 429	1 515	1 568	1 670	36	40	43	53
Japan	-0.1	-0.6	-0.6	-0.6	124	119	116	105	92	93	93	95
Southeast Asia	1.2	0.8	0.7	0.5	685	723	745	787	52	56	58	66
World	1.2	0.9	0.8	0.7	8 018	8 518	8 851	9 680	57	60	62	68

Notes: C & S America = Central and South America. See Annex for composition of regional groupings.

Sources: IEA databases and analysis based on (UN DESA, 2022), (UN DESA, 2018), (World Bank, 2024), (OECD, 2024).

Rates of population growth for each GEC Model region are based on the medium-fertility variant projections contained in the United Nations Population Division report from 2022 (UN DESA, 2022). By the time of the publication of this year's report by the UN (July 2024) the GEC modelling cycle was already advanced, therefore the latest timeseries could not be incorporated as driver inputs. In the 2024 GEC modelling cycle, population rises from slightly over 8 billion in 2023 to around 9.7 billion in 2050. Population growth slows over the projection period, in line with past trends: from 1.2% per year in 2000-2023 to 0.9% in 2023-2030, due in large part to falling global fertility rates as average incomes rise.

Around three-fifths of the increase in the global population to 2050 is in Africa, underlining the importance of the African continent to the achievement of the world's Sustainable Development Goals. Around one-quarter

more is in the Asia Pacific region, where India alone accounts for almost 15% of the growth, having become the world's most populous country in 2023, as China's population growth stalled and started to decline.

Estimates of the rural/urban split for each GEC Model region have been taken from (UN DESA, 2018). This database provides the percentage of population residing in urban areas by country by year over the projection horizon. By combining this data with the UN population projections, an estimate of the rural/urban split can be calculated. In 2023, about 57% of the world population is estimated to be living in urban areas. This is expected to rise to 68% by 2050.

2.2 Macroeconomic assumptions

Table 2.2 ▶ GDP average growth assumptions by region

	Compound average annual growth rate			
	2011-23	2023-35	2035-50	2023-50
North America	2.2%	2.1%	1.9%	2.0%
United States	2.3%	2.1%	1.9%	1.9%
Central and South America	1.0%	2.5%	2.3%	2.4%
Brazil	0.8%	2.1%	2.3%	2.2%
Europe	1.7%	1.8%	1.4%	1.5%
European Union	1.4%	1.5%	1.1%	1.2%
Africa	3.0%	4.0%	4.0%	4.0%
South Africa	1.0%	1.3%	2.7%	2.3%
Middle East	2.1%	3.3%	3.1%	3.2%
Eurasia	1.9%	1.7%	1.4%	1.5%
Russia	1.4%	1.0%	0.6%	0.7%
Asia Pacific	4.7%	4.1%	3.0%	3.3%
China	6.2%	3.7%	2.4%	2.7%
India	5.9%	6.5%	4.3%	4.8%
Japan	0.8%	0.7%	0.7%	0.7%
Southeast Asia	4.2%	4.7%	3.4%	3.7%
World	3.0%	3.1%	2.5%	2.7%

Note: Calculated based on GDP expressed in year-2023 US dollars in purchasing power parity terms.

Source: IEA analysis based on (Oxford Economics, 2024a) and (IMF, 2024).

Economic growth assumptions for the short to medium term are broadly consistent with the latest assessments from the IMF and Oxford Economics. Over the long term, growth in each GEC Model region is assumed to converge to an annual long-term rate. This is dependent on demographic and productivity trends, macroeconomic conditions and the pace of technological change.

In GEC Model 2024 scenarios, the global economy is assumed to grow by 2.7% per year on average over the period to 2050, with large variations by country, by region and over time (Table 2.2).

We recognise that the speed, structure and selection of policy and regulatory mechanisms driving changes in the energy system will have broader economic effects, both positive and negative, across various countries and regions. However, the assumed rates of economic growth are held constant across the scenarios, which allows for a comparison of the effects of different energy and climate choices against a common backdrop.

2.3 Prices

2.3.1 International fossil fuel prices

Table 2.3 ▶ Fossil fuel prices by scenario

USD (MER, 2023)	STEPS			APS			NZE			
	2023	2030	2040	2050	2030	2040	2050	2030	2040	2050
IEA crude oil (USD/barrel)	82	79	77	75	72	63	58	42	30	25
Natural gas (USD/MBtu)										
United States	2.7	3.9	4.1	4.2	3.2	3.0	2.9	2.1	2.0	2.0
European Union	12.1	6.5	7.6	7.7	6.0	5.2	5.2	4.4	4.1	4.0
China	11.5	7.2	8.2	8.3	6.9	6.2	6.2	5.0	4.8	4.8
Japan	13.0	8.3	8.8	8.7	6.8	6.1	6.2	5.0	4.8	4.8
Steam coal (USD/tonne)										
United States	57	51	42	40	42	31	27	28	23	23
European Union	129	68	69	64	64	51	48	57	43	39
Japan	174	105	86	82	81	66	61	66	53	49
Coastal China	150	101	88	82	78	67	61	64	54	49

Notes: MBtu = million British thermal units. The IEA crude oil price is a weighted average import price among IEA member countries. Natural gas prices are weighted averages expressed on a gross calorific value basis. The US natural gas price reflects the wholesale price prevailing on the domestic market. The European Union and China natural gas prices reflect a balance of pipeline and LNG imports, while the Japan gas price is solely LNG imports. The LNG prices used are those at the customs border, prior to regasification. Steam coal prices are weighted averages adjusted to 6 000 kilocalories per kilogramme. The US steam coal price reflects mine mouth prices plus transport and handling costs. Coastal China steam coal price reflects a balance of imports and domestic sales, while the European Union and Japanese steam coal prices are solely for imports.

Source: IEA GEC Model 2024.

International prices for coal, natural gas and oil in the GEC Model reflect the price levels that are needed to stimulate sufficient investment in supply to meet projected demand. They are one of the fundamental drivers for determining fossil fuel demand and supply projections in all sectors and are derived through iterative modelling.

The supply modules calculate the production of coal, natural gas and oil that is stimulated under a given price trajectory, considering the costs of various supply options and the constraints on resources and production rates. If prices are too low to encourage sufficient production to cover global demand, the price level is increased, and energy demand is recalculated. The new demand resulting from this iterative process is again fed back into the supply modules until a balance between demand and supply is reached for each projected year.

The price trajectories do not attempt to represent the fluctuations and price cycles that characterise commodity markets in practice. The potential for volatility is ever present, especially in systems that are undergoing a necessary and profound transformation.

Fossil fuel price paths vary across the scenarios (Table 2.3). For example, in the Stated Policies Scenario (STEPS), although policies are adopted to reduce the use of fossil fuels, demand is still high. That leads to higher prices than in the Announced Pledges Scenario (APS) and the Net Zero Emissions by 2050 Scenario (NZE Scenario), where the lower energy demand means that limitations on the production of various types of resources are less significant and there is less need to produce fossil fuels from resources higher up the supply cost curve.

2.3.2 CO₂ prices

Table 2.4 ► CO₂ prices for electricity, industry and energy production in selected regions by scenario

USD (2023) per tonne of CO ₂	2030	2035	2040	2050
Stated Policies Scenario				
Canada	126	126	126	126
Chile and Colombia	21	24	28	28
China	39	43	46	52
European Union	140	145	149	158
Korea	56	65	73	89
Announced Pledges Scenario				
Advanced economies with net zero emissions pledges ¹	135	160	175	200
Emerging market and developing economies with net zero emissions pledges ²	40	65	110	160
Other emerging market and developing economies	-	6	17	47
Net Zero Emissions by 2050 Scenario				
Advanced economies with net zero emissions pledges	140	180	205	250
Emerging market and developing economies with net zero emissions pledges	90	125	160	200
Selected emerging market and developing economies (without net zero emissions pledges)	25	50	85	180
Other emerging market and developing economies	15	25	35	55

Note: Values are rounded.

¹ Includes all OECD countries except Mexico.

² Includes China, India, Indonesia, Brazil and South Africa.

Source: IEA GEC Model 2024.

CO₂ price assumptions are one of the inputs into the GEC Model as the pricing of CO₂ emissions affects demand for energy by altering the relative costs of using different fuels. There are 75 direct carbon pricing instruments existing today, covering around 50 countries and 40 subnational jurisdictions. Many others have schemes under development or are considering doing so. All scenarios consider the effects of other policy measures alongside CO₂ pricing, such as coal phase-out plans, efficiency standards and renewable targets. These policies interact with carbon pricing; therefore, CO₂ pricing is not the marginal cost of abatement as is often the case in other modelling approaches.

The STEPS takes into consideration all existing or scheduled carbon pricing schemes, at national and subnational level, covering electricity generation, industry, energy production sectors and end-use sectors, e.g. aviation, road transport and buildings, where applicable. In the APS, higher CO₂ prices are introduced across all regions with net zero emissions pledges. In addition, several developing economies are assumed to put in place schemes to limit CO₂ emissions. All regional markets have access to offsets, which is expected to lead to a convergence of prices. No explicit pricing is assumed in sub-Saharan Africa (excluding South Africa) and Other Asia regions. Instead, these regions rely on direct policy interventions to drive decarbonisation in the APS. In the NZE Scenario, CO₂ prices cover all regions and rise rapidly across all advanced economies as well as in emerging economies with net zero emissions pledges, including China, India, Indonesia, Brazil and South Africa. CO₂ prices are lower, but nevertheless rising, in other emerging economies such as in North Africa, Middle East, Russia and other Southeast Asia. CO₂ prices are lower in all other emerging market and developing economies, as it is assumed they pursue more direct policies to adapt and transform their energy systems (Table 2.4).

2.3.3 End-user prices

Fuel end-use prices

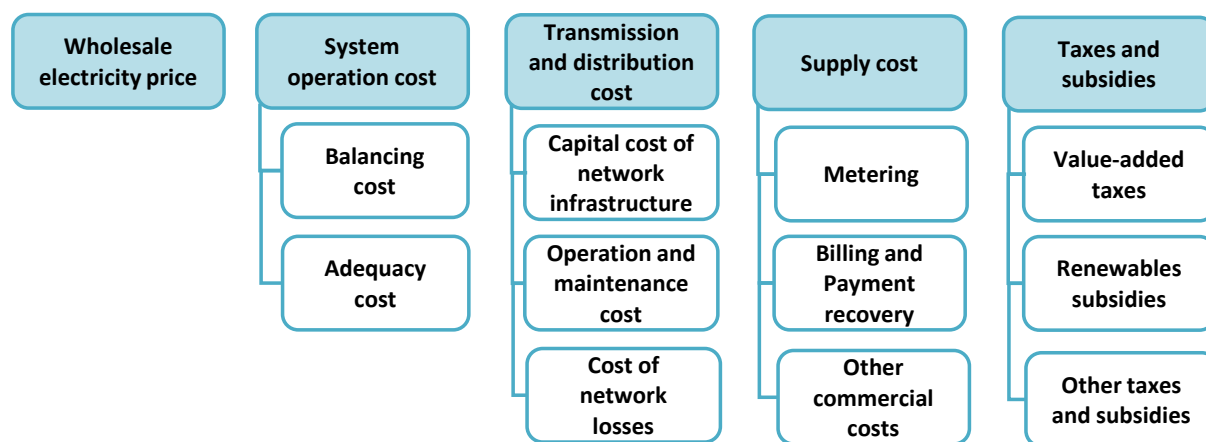
For each sector and GEC Model region, a representative price (usually a weighted average) is derived, taking into account the product mix in final consumption and differences between countries. International price assumptions are then applied to derive average pre-tax prices for coal, oil, and gas over the projection period. Where applicable, excise taxes, value-added tax rates, subsidies and CO₂ prices are included in the average post-tax prices for all fuels. In all cases, the excise taxes and value-added tax rates on fuels are assumed to remain unchanged over the projection period. We assume that energy-related consumption subsidies are gradually reduced over the projection period, though at varying rates across regions and scenarios. Governmental actions to shield consumers are also taken into account.

In the APS and the NZE Scenario, the international oil price drops in comparison to the STEPS due to lower demand for oil products. To counteract a rebound effect in the transport sector from lower gasoline and diesel prices, a CO₂ tax in the form of an increase on fuel duty is applied whenever is necessary for ensuring that end-user prices are kept at least at the same level as in the STEPS. All prices are expressed in US dollars and assume no change in exchange rates over the projection period.

Electricity end-use prices

The model calculates electricity end-use prices as a sum of the wholesale electricity price, system operation cost, transmission and distribution costs, supply costs, and taxes and subsidies (Figure 2.1).

Figure 2.1 ▶ Components of retail electricity end-use prices



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There is no single definition of wholesale electricity prices, but in the GEC Model the wholesale price refers to the average price paid to generators for their output. For each region, wholesale electricity prices are derived under the assumption that all plants operating in a given year recover the full costs – i.e. fixed costs as well as variable costs – of electricity generation and storage. The key region-specific factors affecting wholesale prices are therefore:

- The upfront capital investment and financing costs of electricity generation and storage plants.
- The operation and maintenance costs of electricity generation and storage plants.
- The variable fuel cost of coal, natural gas, oil and other input fuels and, if applicable, the CO₂ cost of generation plants' output.

System operation costs are taken from external studies and are increased in the presence of variable renewables in line with the results of these studies. Transmission and distribution tariffs are estimated based on a regulated rate of return on assets, asset depreciation and operating costs. Supply costs are estimated from historic data, and taxes and subsidies are also taken from the most recent historic data, with subsidy phase-out assumptions incorporated over the outlook period in line with the relevant assumptions for each scenario.

Fossil fuel subsidies

The IEA measures fossil fuel consumption subsidies (IEA, 2023) using a price-gap approach. This compares final end-user prices with reference prices, which correspond to the full cost of supply, or, where appropriate, the international market price, adjusted for the costs of transportation and distribution. The estimates cover subsidies to fossil fuels consumed by end-users and subsidies to fossil-fuel inputs to electricity generation.

The price-gap approach is designed to capture the net effect of all subsidies that reduce final prices below those that prevail in a competitive market. However, estimates produced using the price-gap approach do not capture all types of interventions known to exist. Therefore, they tend to understate the impact of subsidies on economic efficiency and trade. Despite these limitations, the price-gap approach is a valuable tool for estimating subsidies and comparing subsidy levels across countries to support policy development (Koplow, 2009).

2.4 Policies

Underpinning the scenario analysis, an extensive effort is made to update and expand the list of energy and climate-related policies and measures that feed into our modelling. Assumptions about government policies are critical to this analysis and are the main reason for the differences in outcomes across the scenarios.

Two notable IEA policy tracking efforts provide input into the scenarios:

- **Energy Policy Inventory:** The IEA's Energy Policy Inventory provides a unique database on the current state of energy policy worldwide. This tracker inventories the most up-to-date policies for more than 50 countries in the IEA's Policies and Measures Database. It captures regulations, government spending programmes and trade policies by bringing together regular updates from the IEA's Government Energy Spending Tracker, along with information on carbon capture, utilisation and storage (CCUS), methane abatement, hydrogen and critical minerals policies. This policy information has been collected from governments, partner organisations and IEA analysis. Governments have an opportunity to review the policy information periodically.
- **SDG 7 database:** The IEA is at the forefront of global efforts to assess and analyse the persistent deficit in energy access, providing annual country-by-country data on access to electricity and clean cooking (SDG 7.1) and the main data source for tracking official progress towards SDG targets on renewables (SDG 7.2) and energy efficiency (SDG 7.3). The IEA is one of the appointed co-custodians for tracking global progress on SDG 7 alongside IRENA, UNSD, the World Bank, and the World Health Organization (WHO).

New policies and measures globally have been considered during the model preparation, such as the Inflation Reduction Act (United States), Fit for 55 (European Union), Climate Change Bill (Australia), and GX Green Transformation (Japan). A summary of key policy targets and measures by sector in selected countries and regions can be found in Annex B of *World Energy Outlook-2024*.

The policies considered are additive across scenarios: measures listed under the APS supplement those in the STEPS. Additional policy assumptions are incorporated in the NZE Scenario, presented as indicative policy-making and decarbonisation milestones that would steer global energy systems to these outcomes.

The published tables begin with broad cross-cutting policy frameworks, followed by more detailed policies by sector: power, industry, buildings and transport. The tables only list policies that have been enacted, implemented or revised since the last publication cycle. Some regional policies have been included if they play a significant role in shaping energy at a global scale (e.g. regional carbon markets and standards in very large provinces or states). The tables do not include all policies and measures; rather they highlight the policies principally shaping global energy demand today, being derived from an exhaustive examination of announcements and plans in countries around the world. Industry-led initiatives and manufacturing targets that are partially or fully met in the IEA scenarios are the final element making up Annex B.

2.5 Techno-economic inputs

Incorporation of a diverse range of technologies is a key feature of the GEC Model. Extensive research is undertaken to update the range of technologies in the model, as well as their techno-economic assumptions.

The GEC Model includes the breadth of technologies that are available on the market today. Additionally, the model integrates innovative technologies and individual technology designs that are not yet available on the market at scale by characterising their maturity and expected time of market introduction. For each sector and technology area, new project announcements and important technological developments are tracked in databases that are regularly published.

The modelled scenarios are informed by a similarly detailed technology tracking process. For instance, the project planning financing status is an important consideration for whether projects are reflected in the STEPS or rather in the APS. For technology development progress and the time to bring new technologies to markets, the scenarios assume a different pace of progress as the support and degree of international co-operation on clean energy innovation increases with ambition on decarbonisation.

The following databases are particularly relevant for the definition of the different scenarios:

- Clean innovative technologies tracking:
 - **Clean Technology Guide:** interactive database that tracks the Technology Readiness Level (TRL) of almost 600 individual technology designs and components across the whole energy system that contribute to achieving the goal of net zero emissions. The guide is updated every year.
 - **Clean Energy Demonstration Projects Database:** launched in 2022 and updated every year, this provides more detailed tracking of the location, status, capacity, timing and funding of over 500 demonstration projects across the energy sector.
 - **Tracking Clean Energy Progress:** annual tracking of market deployment and techno-economic performance metrics for over 50 components of the energy system that are critical for clean energy transitions and their progress towards short-term 2030 milestones along the trajectory of the NZE Scenario.
- **Hydrogen Production Projects Database:** covers all projects commissioned worldwide since 2000 to produce hydrogen for energy or climate-change-mitigation purposes.
- **Global EV Outlook:** annual publication that identifies and discusses recent policy and market developments in electric mobility across the globe. It is developed with the support of the members of the Clean Energy Ministerial Electric Vehicles Initiative (EVI).

Technology costs are an important input to the model. All costs represent fully installed/delivered technologies, not solely the equipment cost, unless otherwise noted as for fuel cells. Installed/delivered costs include

engineering, procurement and construction costs to install the equipment. Some illustrative examples include the following:

- **Iron-based steel** production costs display a range considering technology and regional differences and differentiate between conventional and innovative production routes. Conventional routes are unabated blast furnace-basic oxygen furnace (BF-BOF) and direct reduced iron-electric arc furnace (DRI-EAF). The innovative routes are BF-BOFs with CCUS, DRI-EAF with CCUS, and 100% electrolytic hydrogen-based DRI-EAF.
- **Vehicle** costs reflect production costs, not retail prices, to better reflect the cost declines in total cost of manufacturing, which move independently of final market prices for electric vehicles to customers. Historical values in 2023 have been used for the global average battery pack size. In hybrid cars, the future cost increase is driven by regional fuel economy and emissions standards.
- **Electrolyser** costs reflect a projected weighted average of installed electrolyser technologies (excluding China, where the modelled costs are lower), including inverters.
- **Fuel cell** costs are based on stack manufacturing costs only, not installed/delivered costs. The costs provided are for automotive fuel-cell stacks for light-duty vehicles.
- **Utility-scale stationary battery** costs reflect the average installed costs of all battery systems rated to provide maximum power output for a four-hour period.

Table 2.5 ▶ Capital costs for selected technologies by scenario

	Stated Policies			Announced Pledges			Net Zero Emissions by 2050			
	2023	2030	2035	2050	2030	2035	2050	2030	2035	2050
Levelised cost of iron-based steel production (USD/t)										
Conventional										
Lower range	510	470	470	470	500	530	590	550	600	730
Upper range	630	560	560	560	690	730	770	750	770	850
Innovative										
Lower range	n.a	650	660	650	680	700	650	730	670	680
Upper range	n.a	870	880	850	960	880	820	910	760	830
Vehicles (USD/vehicle)										
Hybrid cars	17 500	15 100	15 000	15 000	15 100	15 000	14 900	15 100	15 000	14 900
Battery electric cars	18 900	15 800	14 700	13 700	15 100	14 200	13 300	14 800	13 600	12 900
Batteries and hydrogen										
Hydrogen electrolysers (USD/kW)										
Lower range	1 300	850	810	710	750	620	550	640	560	520
Upper range	2 160	1 320	1 180	1 010	1 050	940	820	960	860	780
Fuel cells										
(USD/kW)	90	65	55	45	55	45	35	50	40	30
Utility-scale stationary batteries										
(USD/kWh)	250	175	155	130	170	150	125	165	145	120

Notes: t= tonnes; kW = kilowatt; kWh = kilowatt-hour. All values are in USD (2023).

End-use sectors

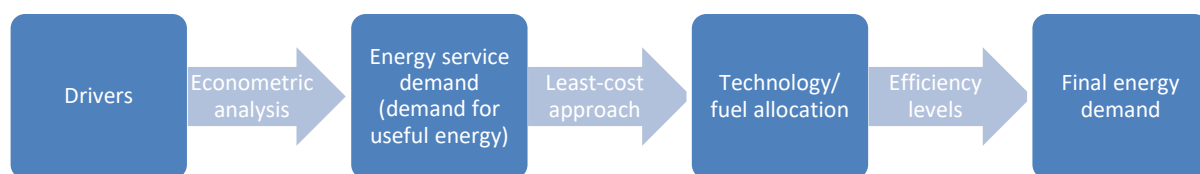
All 27 regions are modelled in considerable sectoral and end-use detail. Specifically:

- **Industry** is composed of five energy-intensive and eight non-energy-intensive sub-sectors.
- **Buildings** is separated into residential and services buildings, with six end uses modelled separately.
- **Transport** is separated into nine modes with considerable detail for road transport.
- **Agriculture** modelling reflects the range of fuels and energy-consuming applications in the sector.

Total final energy demand is the sum of energy consumption in each final demand sector. In each sub-sector or end-use, at least seven types of energy are shown: coal, oil, gas, electricity, heat, hydrogen and renewables. The main oil products – liquefied petroleum gas (LPG), naphtha, gasoline, kerosene, diesel, heavy fuel oil (HFO) and ethane – are modelled separately for each final sector.

Demand-side drivers, such as steel production in industry or household size in buildings, are estimated econometrically based on historical data and on socio-economic drivers (such as GDP and population). All end-use sector modules base their projections on the existing stock of energy infrastructure. This includes the number of vehicles in transport, production capacity in industry, and floor space area in buildings. To take into account expected changes in structure, policy or technology, a wide range of technologies that can satisfy each specific energy service are integrated in the model. End-user fuel prices and technology costs play an important role in determining the distribution of technologies and fuels, although real-world non-cost influences also play a role. Respecting the efficiency level of all end-use technologies gives the final energy demand for each sector and sub-sector (Figure 3.1).

Figure 3.1 ▶ General structure of demand modules



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3.1 Industry

Industry is the most energy-consuming and CO₂-emitting end-use sector. It accounts for 39% of total final energy consumption and 45% of CO₂ emissions (including emissions from electricity and heat). The industry model covers five energy-intensive sectors – accounting for 70% of global industry energy demand:

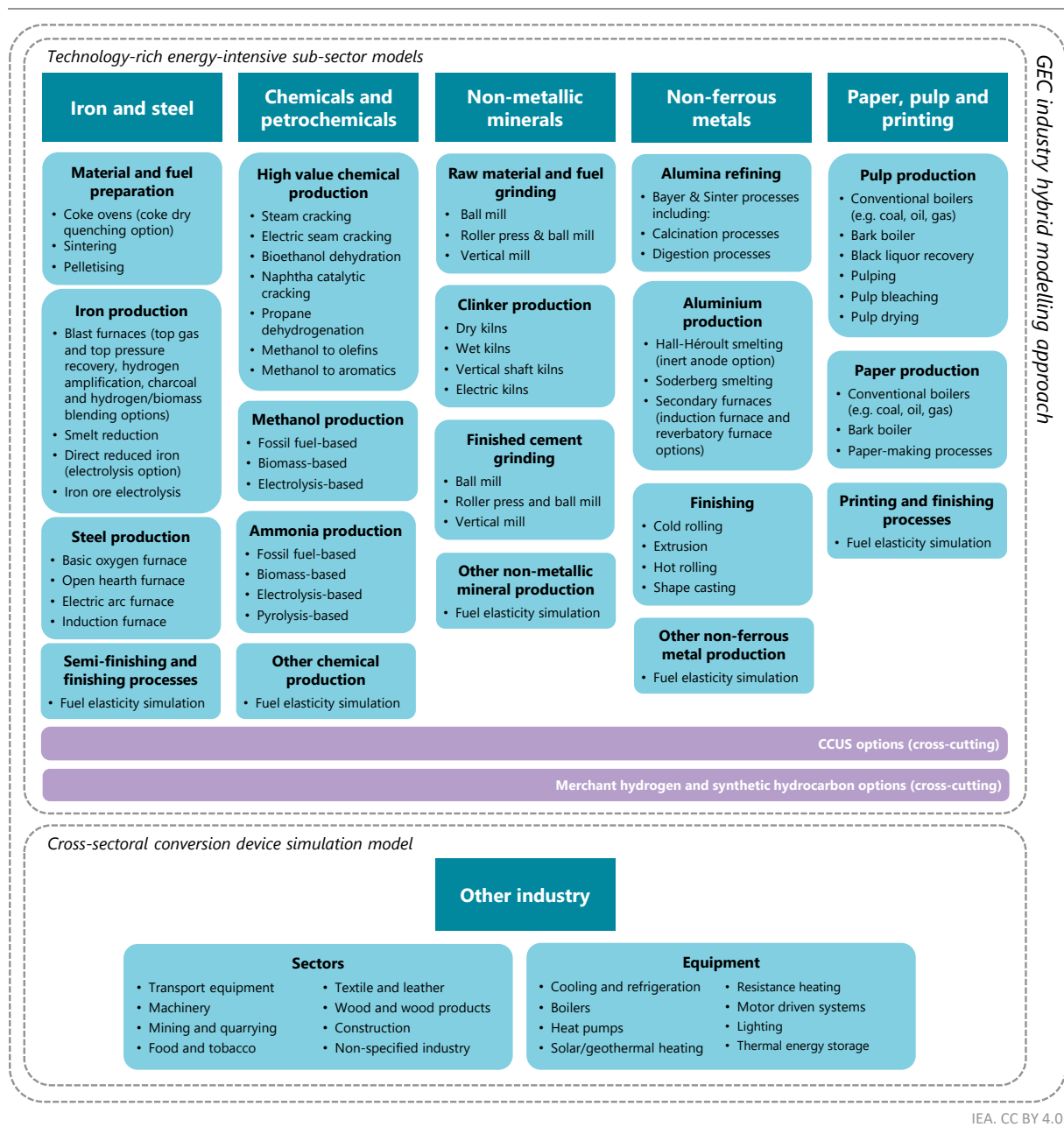
- iron and steel, with technology-rich modelling of iron and steel production
- chemicals, with technology-rich modelling of ammonia, methanol and high-value chemicals production
- non-metallic minerals, with technology-rich modelling of cement production
- non-ferrous metals, with technology-rich modelling of alumina and aluminium production
- paper, pulp and printing.

It also covers eight non-energy-intensive sectors: construction; food and tobacco; machinery; mining and quarrying; transportation equipment; wood and wood products; and other industry not specified elsewhere.

The industry sector model combines the strengths of both simulation and optimisation models into a single simulation framework, with its constraints and input parameters informed by periodic model runs of the former ETP TIMES optimisation framework, among other things.

3.1.1 Industry model coverage and approach

Figure 3.2 ▶ Major categories of technologies by end-use sub-sector in industry



For the purposes of the GEC industry model, the industrial sector includes International Standard Industrial Classification (ISIC) Divisions 7, 8, 10-18, 20-32 and 41-43, and Group 099, covering mining and quarrying (excluding mining and extraction of fuels), construction, and manufacturing. This coverage follows the structure of the IEA Energy Balances, covering all the industry components of total final consumption. Chemical feedstock (a component of non-energy use) and blast furnace and coke oven energy use (both transformation and own use) are also included within the boundaries of industry. Final industrial energy consumption includes all electricity used in industrial processes including that generated onsite (e.g. via captive combined heat and power units). Thus, fuel used to generate electricity onsite is excluded from that reporting to avoid double counting, and this fuel is accounted for in the transformation sector. Aside from petrochemical feedstock, other

non-energy use is not included in the GEC Model’s industry sector boundary, but rather is modelled as a separate category in the same framework.

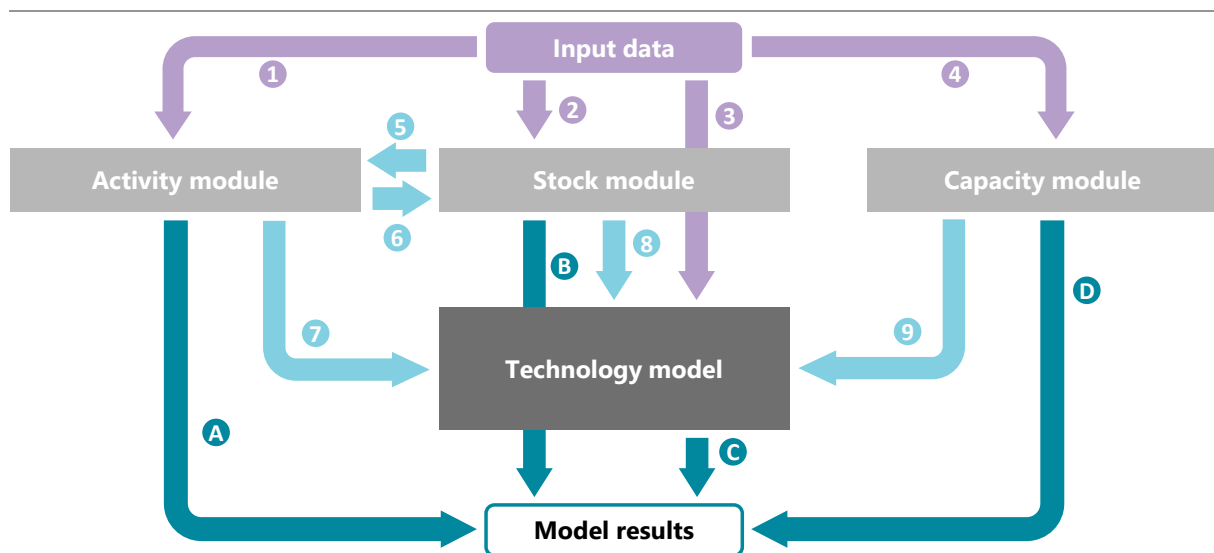
The industry sector is modelled using a hybrid approach (Figure 3.2). Technology-rich simulation models, informed by periodic model runs of the former ETP TIMES optimisation framework, are used for five energy-intensive sub-sectors components thereof (iron and steel; primary chemicals within chemicals and petrochemicals; cement within non-metallic minerals; aluminium within non-ferrous metals; paper, pulp and printing). The remaining non-energy-intensive industry sub-sectors (construction, mining and quarrying, transport equipment, machinery, food and tobacco, wood and wood products, textile and leather, and industry not-elsewhere specified) are modelled using a cross-cutting conversion device simulation approach. For the residual components of the five energy-intensive sub-sectors (chemicals besides primary chemicals, non-metallic minerals besides cement, non-ferrous metals besides aluminium, downstream finishing processes in the iron and steel sector, and paper, pulp and print sector), a similar cross-cutting approach is applied as to the non-energy-intensive sub-sectors.

The five energy-intensive sub-sector models characterise the energy performance of process technologies at the process unit level (e.g. coal blast furnace, naphtha steam cracker). The cross-cutting simulation model for the remaining industry sub-sectors characterises the stock of the main conversion devices (e.g. motors, heating equipment) used to provide various energy services required during the production of thousands of materials and products. See the subsections below for more information on the approaches taken for each of these components of the GEC industry model.

3.1.2 Energy-intensive sub-sectors

For each of the five energy-intensive industry sub-sectors, the modelling framework consists of a series of interacting sub-modules and a core technology model (see Figure 3.3). The sub-modules consist of an activity model, a stock model and a capacity model.

Figure 3.3 ▶ Industry sector model internal module structure and key data flows



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Notes: Internal industry model flows: 1) Historic production, population projection, industry value-added projection; 2) End-use demand, product lifetimes, process yields, recycling and reuse rates; 3) Energy and raw material intensities, energy prices, CAPEX and operational expenditures (OPEX), lifetimes, technology deployment constraints, CO₂ emissions reduction trajectory; 4) Historic and planned capacity, lifetimes, refurbishments; 5) Consumption projections; 6) Material stocks saturation, material efficiency factors; 7) Production projections including trade; 8) Scrap availability; and 9) Residual capacity. Model results: A) Material production; B) Material stocks saturation; C) Energy consumption, CO₂ emissions, technology shares, investments; and D) Capacity installed, added and retired.

The activity drivers for each sub-sector of the GEC industry model are tonnages of material produced in a given scenario at a given point in time. Activity modelling is handled in a similar manner for all energy-intensive industry sub-sectors. Demand for materials is projected through interaction between an activity model and a stock model, together with modelling of material efficiency strategies. The activity model uses country-level historical data on material consumption to calculate demand per capita, then projects forward total demand using population projections and industry value-added projections (both sub-sector and total industry value-added). The industry value-added projections inform the change in demand per capita.

The results of the activity model on demand projections feed into the stock model, which uses bottom-up material demand inputs from the buildings, transport and supply modules, and complementary assumptions about other end-product shares and lifetimes to calculate the implied build-up of material stocks. Stock saturation in the stock model in turn informs per-capita material demand saturation in the activity model through a series of iterations.

Material efficiency strategies across value chains are also modelled. This modelling work builds mainly on the literature and previous IEA publications relating to material efficiency (IEA, 2019). Strategies considered include:

- **Design stage:** light-weighting (producing the same product with a lower average mass per product), design for future material savings (modular design to enable reduction, design for recyclability)
- **Construction and manufacturing:** increased yields (reducing the losses in semi-manufacturing and manufacturing), reduced materials waste (more careful construction practices and material handling)
- **Use:** longer lifetimes (refurbishing buildings for other uses, re-using components for particular products), more intensive use of products (for example car sharing or using a building for a larger share of the day)
- **End-of-life:** direct materials reuse (use of post-consumer materials – without re-melting in the case of metals – for the same or other applications), recycling (increased collection, improved sorting, and development of advanced recycling technologies).

Those strategies occurring in the other end-use sectors (e.g. building lifetime extension, vehicle light-weighting) are fed into the activity modelling via bottom-up demand estimates, while material efficiency strategies within the industry boundary (e.g. manufacturing yield improvements, direct reuse and recycling) are modelled within the stock model. These strategies lead to reduced material demand, which is fed into the activity model via a material efficiency factor. The resulting activity projections from the activity model and scrap availability (including semi-manufacturing, manufacturing and post-consumer scrap) from the stock model feed into the main technology model.

Material trade for steel, aluminium and ammonia (for final or intermediate products) between model regions is modelled through IEA's Manufacturing and Trade (MaT) model. This projects trade flows based on the optimisation of overall manufacturing and trade costs under different scenarios to 2050. More information on the MaT model methodology is included in the forthcoming ETP-2024 report. For other materials, trade is not modelled endogenously in the technology model, but rather is reflected in the activity projections developed in the activity and stock models. Apart from specific instances where announced policies or projected energy price signals provide relevant evidence to the contrary, trade patterns in material production and consumption are projected to follow current trends. Regional material production and demand are consistent with these projections of net trade patterns.

The capacity model contains data on historic and planned plant capacity additions and retrofits by plant type. Using assumptions about investment cycles, it calculates plant refurbishments and retirements. The resulting remaining capacity informs the main technology model. The capacity model also provides projections on the average age of plants at a given time, and allows calculation of investment requirements.

The main technology model of each sector consists of a detailed representation of process technologies required for relevant production routes. Energy use and technology portfolios for each country or region are characterised in the base year using relevant energy use and material production statistics. Throughout the modelling horizon, demand for materials (as dictated by the activity model outputs) is met by technologies and fuels, whose shares are informed by announced projects, policies and support schemes, real-world technology progress and the previous ETP TIMES optimisation model. That model uses a constrained optimisation framework, with the objective function set to make choices that minimise overall system cost (comprised of both energy costs and investments).

Changes in the technology and fuel mix, as well as efficiency improvements, are in part driven by a combination of exogenous assumptions on the penetration and energy performance of best available technologies, constraints on the availability of raw materials (such as scrap availability according to the stock model outputs), techno-economic characteristics of the available technologies and process routes, and assumed progress on demonstrating innovative technologies at commercial scale. The results are sensitive to assumptions about how quickly physical capital is turned over (including retirements of existing capacity according to the capacity model outputs) and about the relative costs of the various technology options and fuels. A given scenario can also be subject to a CO₂ emission trajectory that the model must adhere to. Model outputs include energy consumption, heat by temperature level, fuel combustion and process CO₂ emissions both emitted and captured, technology shares, raw materials and intermediate industrial materials flows, and investment requirements.

Some industrial sectors have the particularity of producing and using “onsite” hydrogen within the industrial facility, such as for specific ammonia, methanol or iron-based steel production processes. This hydrogen is not reported in standard energy balances, but it is reported as fossil fuel or electricity depending on whether it is produced via steam reforming or water electrolysis. Accounting of this hydrogen, which is necessary to build the global hydrogen accounting, is performed in a dedicated hydrogen module. Outputs of this module are hydrogen quantities produced onsite (low-emissions or not), electrolyser capacity and related investment requirements, energy input and related CO₂ emissions emitted as well as captured and stored.

3.1.3 Non-energy-intensive sub-sectors

Activity modelling for the non-energy-intensive sub-sectors follows a different approach to the energy-intensive sectors. These sub-sectors produce a large range of final products without a clear common intermediate in many cases. This contrasts to the energy-intensive sub-sectors, which have a large range of final products but a clear common intermediate product for which production in physical terms can be clearly projected (e.g. crude steel in the iron and steel sector). As such, macroeconomic indicators (e.g. industrial value added) are used as the activity drivers for non-energy-intensive sub-sectors, rather than physical production. Using historical relationships between macroeconomic indicators and industrial energy demand, together with demand signals from the other end-use models (e.g. vehicle sales from the transport model for the transport equipment sector; clean technology manufacturing mostly for the machinery sector; critical mineral and other ore demand for the mining sector) and material efficiency considerations (based on the results of the energy-intensive sub-sector analyses) where relevant, projections of energy service demand are made across the following categories:

- Heat delivered at five temperature bands (0-60 °C, 60-100 °C, 100-200 °C, 200-400 °C and above 400 °C).
- Mechanical work to be delivered by motors.
- Other energy services in aggregate (cooling, lighting etc.)

These energy service demands form the final activity drivers for the non-energy-intensive industry sub-sector models.

A range of technologies are characterised for meeting each category of activity demand, including a range of different heating technologies using different fuels (fossil fuels, solar thermal, geothermal, electric heating, heat pumps, hydrogen, bioenergy), thermal energy storage, and a range of motor options (differing efficiencies of the motor-driven system, efficiencies of the motor itself, variable speed drive option). The shares of energy service demand met by each of these technologies is modelled using a Weibull function. This function is informed by each technology's levelised cost (including fuel price evolution and the impact of any CO₂ prices), constraints on fuel availability (e.g. bioenergy resources), technology readiness, limits on potential (e.g. industrial heat pump penetration in medium and high temperature heat bands) and any CO₂ emissions constraints of the scenario.

The shares of fuels (and associated emissions) used to meet the remaining energy service demand of multifuel processes or processes that are not covered by the bottom-up technology modelling across the non-energy-intensive sectors (and residual portions of the energy-intensive sectors not covered in the energy-intensive sub-sector models) is modelled by fuel using a Weibull function. This function is informed by the evolution of fuel prices (including the impact of any CO₂ prices). Any CO₂ constraints specified by the scenario are also respected.

3.1.4 Industry sector investments

The boundaries for investments reporting include capital expenditure (CAPEX), and engineering, procurement and construction costs. For material efficiency, investments are based on data on CO₂ abatement costs for material efficiency strategies, converted into costs for material savings. Fixed operating and maintenance expenditures (OPEX) are not included under reported investments, though they are considered in the context of the economic characterisation of technologies in the model. Energy system investments do not include CAPEX on core industrial equipment, but do include the additional investment required to incrementally (e.g. energy efficiency improvements through adoption of best available technologies) or substantially (e.g. electrolyser and carbon capture equipment) adjust the energy or emissions performance of a technology. Other investments in core industrial equipment are also accounted for, but not reported within the boundary of energy system investments.

3.1.5 Input data

Input data to the model comes from a wide variety of sources. Sources for historical production and consumption used in the activity modelling include the World Steel Association (worldsteel), the International Fertilizer Association, the United States Geological Survey, the International Aluminium Institute and a number of proprietary sources. Data on the energy intensities of processes come from a variety of industry sources (e.g. the Getting the Numbers Right publication overseen by the Global Concrete and Cement Association), academic literature and industry contacts. CAPEX and OPEX similarly come from a combination of industry and academic sources.

Population, economic indicators (e.g. value added by industry), fuel costs – i.e. end-use energy prices, and CO₂ prices are provided by the main GEC Model (see Section 2). Other key inputs from the GEC modelling framework and associated work streams include the hydrogen and CCUS projects databases and the technology readiness assessments that form part of the Clean Technology Guide and Demonstration Projects Database. Techno-economic parameters are periodically reviewed, both as a component of aforementioned work streams, and during the course of preparing 'deep-dive' analyses on specific sector or technology areas (e.g. the IEA's Iron and Steel Technology Roadmap, the Ammonia Technology Roadmap, The Future of Petrochemicals).

3.2 Transport

The GEC transport model combines the strengths of both the former World Energy Model (WEM) and the Mobility Model (MoMo), and consists of dedicated sectoral models for road transport, aviation, maritime and rail.

3.2.1 The historical database

One key foundation for transport modelling work is the road transport database, which is updated annually based primarily on publicly available data on road vehicle sales, stocks, activity and operations. The road database further benefits from data and analytical work for the Electric Vehicles Initiative (IEA, 2022a). Similar historical databases form the basis for modelling rail, international shipping and commercial passenger aviation.

Each region is characterised on the basis of information that includes — for each road transport mode — vehicle sales, mileage, and energy intensity by vintage, as well as the overall vehicle stock, load factors and fuel efficiency.

The database allows linking historical data on several interconnected variables, trying to assure internal consistency across indicators, according to the ASIF framework, wherein **Activity**, **Structure** and **Intensity** determine estimates of **Fuel** use):

$$F = \sum_i F_i = A \sum_i \left(\frac{A_i}{A}\right) \left(\frac{F_i}{A_i}\right) = A \sum_i S_i I_i = F$$

F	total Fuel use
F_i	fuel used by vehicles with a given set of characteristics (i) (e.g. segments by service, mode, vehicle and powertrain)
A	vehicle Activity (expressed in vehicle-kilometres [vkm])
$A_i/A = S_i$	sectoral Structure (same disaggregation level)
$F_i/A_i = I_i$	Energy Intensity , i.e. average fuel consumption per vkm (same disaggregation level)

The parameters monitored include sales/new registrations of vehicles, second-hand imports, survival ages, stock, mileages, vehicle activity (vehicle-kilometres [vkm]), loads/occupancy rates, passenger and freight activity (passenger-kilometres [pkm] and tonne-kilometres [tkm]), fuel economies and energy use (based on the IEA data on energy demand by country).

The following parameters are collected and calibrated/validated against the road energy balances on an annual basis:

- Sales/new vehicle registration data are taken from publicly available data sources (e.g. the European Automobile Manufacturers' Association [ACEA], US Bureau of Transportation Statistics, and others).
- Fuel economy data for passenger light-duty vehicles are based on aggregated data from a proprietary database, plus conversions (based on an external research report) across regional vehicle test cycles to the World Light-Duty Test Cycle, plus estimates for the gap between this test cycle and real-world specific fuel consumption (again, based on external research reports).
- Fuel economy data for buses, trucks, two/three-wheelers are taken from various academic, government and industry reports or technical calculations, over the course of nearly 20 years.
- Stocks are based on our estimates of how long different vehicle types are kept in the fleet (i.e. scrappage functions), and when reliable external estimates are available (as is the case, for instance, in the United States and Europe), these are calibrated to official data (e.g. ACEA, US Bureau of Transportation

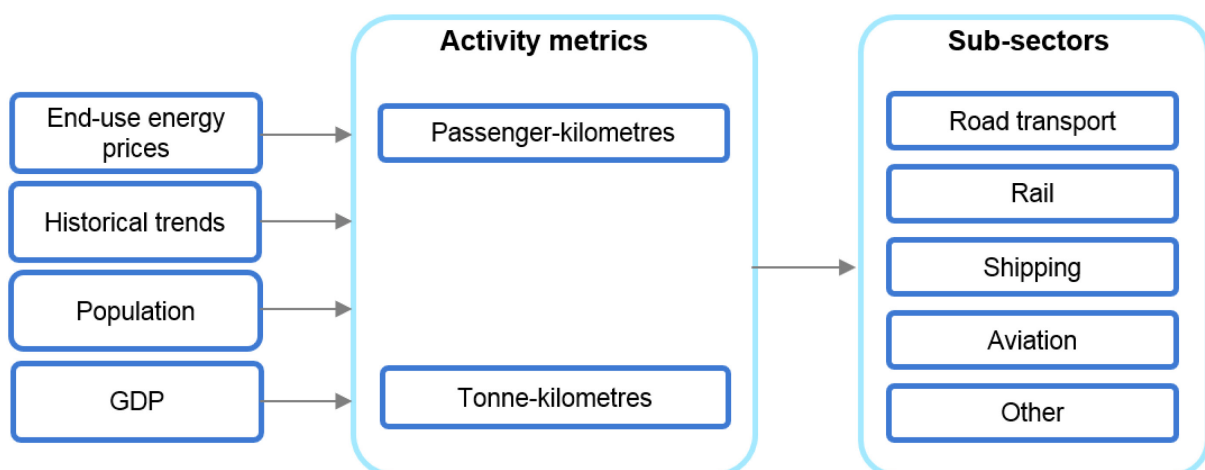
Statistics). In countries where academic or industry studies exist on the age distribution of the on-road fleet, scrappage functions are compared/calibrated with these.

- Occupancy (average people per vehicle) and Load Factors (average cargo weight per vehicle) are based on official statistics (e.g. Eurostat), academic reports or surveys, or are developed by analogy/regression-based estimates when no data are available.
- Average mileage (i.e. annual kilometres driven) estimates are similarly taken from or compared/calibrated to official data and literature.
- Scrappage and mileage are then adjusted, across all vehicle categories (e.g. two/three-wheelers, cars, buses, light commercial vehicles, medium and heavy trucks) and across all fuel/powertrain types (e.g. gasoline, diesel, conventional hybrid, plug-in hybrid, battery and fuel cell electric, etc.) to match the country- or regional-time series of road gasoline, diesel, electricity, natural gas and LPG consumption as reported in the IEA energy balances.

3.2.2 The transport module

The transport module consists of several sub-models covering road, aviation, rail and navigation transport modes (Figure 3.4) and incorporates a detailed bottom-up approach in all model regions.

Figure 3.4 ▶ Structure of the transport demand module



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Note: Other includes pipeline and non-specified transport.

For each region, activity levels such as passenger-kilometres and tonne-kilometres are estimated econometrically for each mode of transport as a function of population, GDP and end-user prices. Transport activity is linked to price through elasticity of fuel cost per kilometre, which is estimated for all modes except trains and inland navigation. This elasticity variable accounts for the “rebound” effect of increased car use that follows improved fuel efficiency. Energy intensity is projected by transport mode, taking into account changes in energy efficiency and fuel prices.

Additionally, analysis of the composition of road vehicles and ships is combined with sales projections to produce estimates of demand for materials such as steel and aluminium over time. These projections inform the IEA's ongoing work on material demand and subsequent heavy industry activity.

Road transport

Road transport energy demand is broken down among passenger light-duty vehicles (PLDVs), light commercial vehicles (LCVs), buses, medium trucks, heavy trucks and two- and three-wheelers. The model allows fuel substitution and alternative powertrains across all sub-sectors of road transport. The gap between test and on-road fuel efficiency, i.e. the difference between test cycle and real-life conditions, is also estimated and projected.

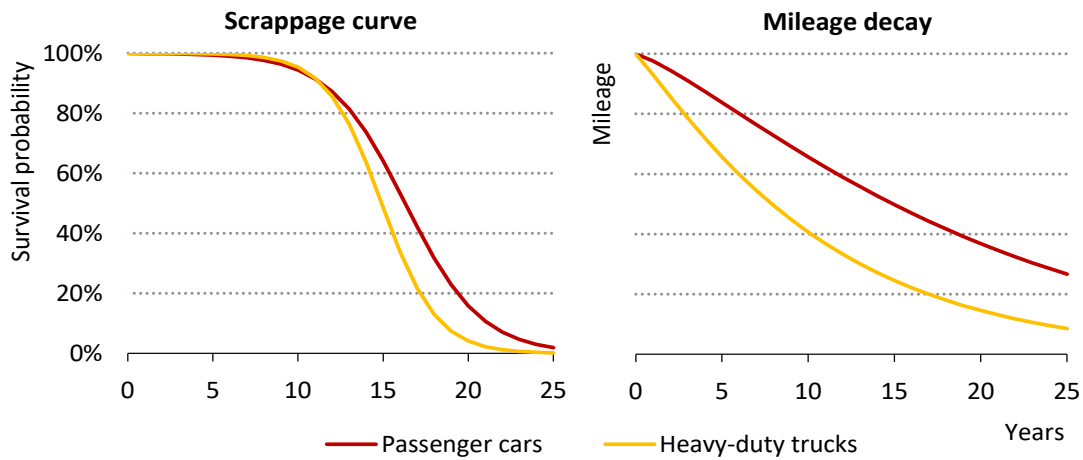
As the largest share of energy demand in transport comes from oil use for road transport, the GEC Model contains technology-detailed sub-models of the total vehicle stock and the passenger car fleet. The stock projection model is based on an S-shaped Gompertz function, proposed in (Dargay, Gately, & Sommer, 2006). This model gives the vehicle ownership based on income (derived from GDP assumptions) and two variables: the saturation level (assumed to be the maximum vehicle ownership of a country/region) and the speed at which the saturation level is reached. The equation used is:

$$V_t = y e^{ae^{bGDP_t}}$$

where V is the vehicle ownership (expressed as number of vehicles per 1 000 people), y is the saturation level (expressed as number of vehicles per 1 000 people), a and b are negative parameters defining the shape of the function (i.e. the speed of reaching saturation). These three parameters (y, a and b) are based on the historical correlation between GDP per capita and vehicle ownership, additionally taking into account several country/region-specific factors such as population density, urbanisation and infrastructure development. Using the equation above, changes in passenger car and two- and three-wheeler ownership over time are modelled, incorporating the curve-fitting approach and the average current global passenger car two- and three-wheeler ownership. Bus ownership projections also take into account competition with non-high-speed passenger rail, with Gompertz curves fitted based on correlation with GDP per capita and the share of public transport in the total road and rail passenger activity. Having already modelled private vehicle and rail activities, we can derive bus activity projections, and later include additional activity shift from PLDVs to buses based on fuel price elasticity projections. Both total vehicle stock and passenger vehicle stock projections are then derived based on our population assumptions. Projected vehicle stocks and corresponding vehicle sales are then benchmarked against actual annual vehicle sales. The resulting vehicle stock projections can therefore differ from those that would be derived using the Gompertz function alone.

To improve the stock evolution of the vehicle fleet, a dynamic scrappage function has been developed where dedicated scrappage curves are estimated by region based on a correlation of average lifetime with economic growth. The dynamic scrappage function allows to evaluate policy measures such as for the early retirement of vehicles (Figure 3.6). To take into account that older vehicles are used less frequently, an extensive literature review has been carried out to identify mileage curves per vehicle type. This enables a more granular assessment of how each vehicle type per vintage (purchase year) is contributing to total road activity.

Figure 3.5 ▸ Illustration of scrappage curve and mileage decay by vehicle type



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The analysis of **passenger light-duty vehicle (PLDV)** uses a cost tool that guides the choice of drivetrain technologies and fuels as a result of their cost-competitiveness. The tool acts on new PLDV sales as depicted in Figure 3.6, and determines the share of each individual technology in new PLDVs sold in any given year.

The purpose of the cost tool is to guide the analysis of long-term technology choices using their cost-competitiveness as one important criterion. The tool uses a logit function for estimating future drivetrain choices in PLDV.¹ The share of each PLDV type j allocated to the PLDV market is given by:

$$Share_j = \frac{b_j P_{PLDV_j}^{r_p}}{\sum_j (b_j P_{PLDV_j}^{r_p})}$$

Where:

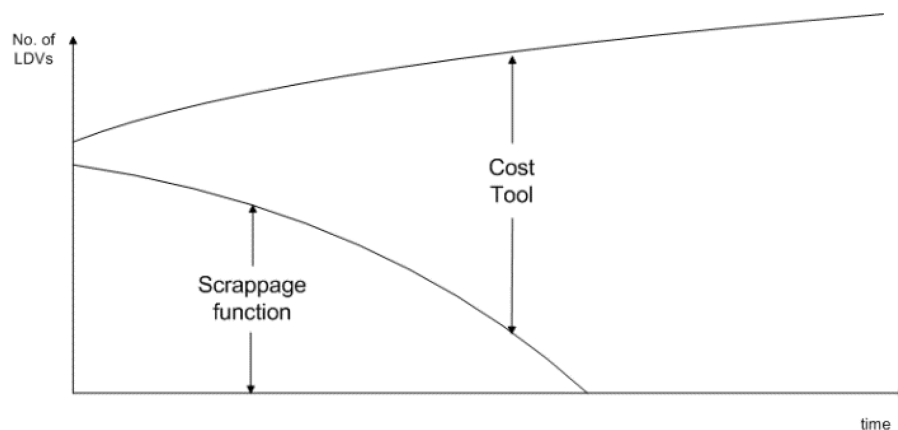
- P_{PLDV_j} is the annual cost of a vehicle, including annualised investment and operation and maintenance costs as well as fuel use;
- r_p is the cost exponent that determines the rate at which a PLDV will enter the market; and
- b_j is the base year share or weight of PLDV _{j} .

The cost database in the cost tool builds on an analysis of the current and future technology costs of different drivetrains and fuel options, comprising the following technology options:

- Conventional internal combustion engine (ICE) vehicles (spark and compression ignition)
- Hybrid vehicles (spark and compression ignition)
- Plug-in hybrids (spark and compression ignition)
- Battery electric cars with different drive ranges
- Hydrogen fuel cell vehicles.

¹ Originally developed to describe the growth of populations and autocatalytic chemical reactions, logit functions can be applied to analyse the stock turnover in different sectors of the energy system. Here, it uses the cost-competitiveness of technology options as an indicator for the pace of growth.

Figure 3.6 ▶ The role of passenger-light-duty vehicle cost model



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Note: LDVs = light-duty vehicles.

The model takes into account the costs of short- and long-term efficiency improvements in personal transport distinguishing numerous options for engine (e.g. reduced engine friction, the starter/alternator, or transmission improvements) and non-engine measures (e.g. tyres, aerodynamics, downsizing, light-weighting or lighting). In addition, it uses projections for the costs of key technologies such as batteries (nickel metal hydride and lithium-ion) and fuel cells. The pace of technology cost reductions is then calculated using learning curves at technology-specific learning rates.

The cost analysis builds on a comprehensive and detailed review of technology options for reducing fuel consumption. The database was reviewed by a panel of selected peer reviewers, and feeds into the cost tool. The cost database is constantly reviewed and takes account of recent research. Cost curves assumptions across all vehicle types are based on work by the Joint Research Centre (JRC) (Krause, 2017), (Krause & Donati, 2018). Regional characteristics and economic factors have been taken into account in order to expand cost curve coverage for all GEC Model regions.

Projected sales of alternative powertrains (focusing primarily on electric vehicles within light-duty vehicles, and electric and fuel cell electric vehicles within heavy-duty sectors) for the top 20 global automakers are regularly updated over the course of each year. This analysis allows for an assessment of whether vehicle manufacturers' commitments for launching new electrified car models are falling behind the necessary electric vehicle (EV) rollout for meeting fuel economy goals and zero emissions vehicle mandates. Vehicle manufacturers and national and state jurisdictions with ICE phase-out commitments for a certain year are also part of this analysis.

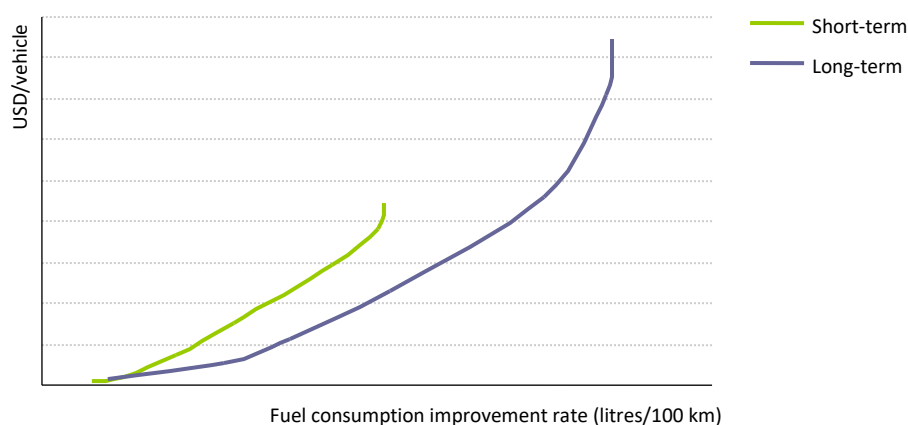
Projections of battery and plug-in electric vehicles battery demand are matched to simple projections of battery pack capacity and (the cell's cathode) chemistry, and these projections are linked to bottom-up analyses of battery costs, and critical mineral requirements. These projections inform the IEA's ongoing work to assess critical minerals demand and value chain implications of a shift to electromobility.

Hydrogen fuel cell electric vehicles projections take into account the recent car market developments, policy announcements and the key outcomes from IEA's *Global Hydrogen Review 2024* (IEA, 2024e).

Road freight transport vehicles can be broadly classified into LCVs (< 3.5 t), medium trucks (3.5 t to 15 t) and heavy trucks (>15 t). For the latter two categories, the GEC Model comprises two detailed sub-models to guide the development of average fuel economy improvements on the one hand, and technology choices on the other hand. For the former, the model endogenises the decision of investments in energy efficiency by taking the view of rational economic agents on the basis that minimising costs is a key criterion for any investment decision in

this sector. Using the efficiency cost curves of JRC, the model calculates the undiscounted payback period of an investment into more fuel-efficient trucks and heavy trucks. The model then allows for investments where the calculated payback period is shorter than an assumed minimum payback period that is required by fleet operators (generally assumed to be between 1 and 3 years, depending on the region). The problem is solved in an iterative manner as the model seeks to deploy the next efficiency step on the efficiency cost curve as determined by literature, but may use efficiency improvement levels in between individual steps on the efficiency cost curve (Figure 3.7).

Figure 3.7 ▶ Illustration of an efficiency cost curve for road freight



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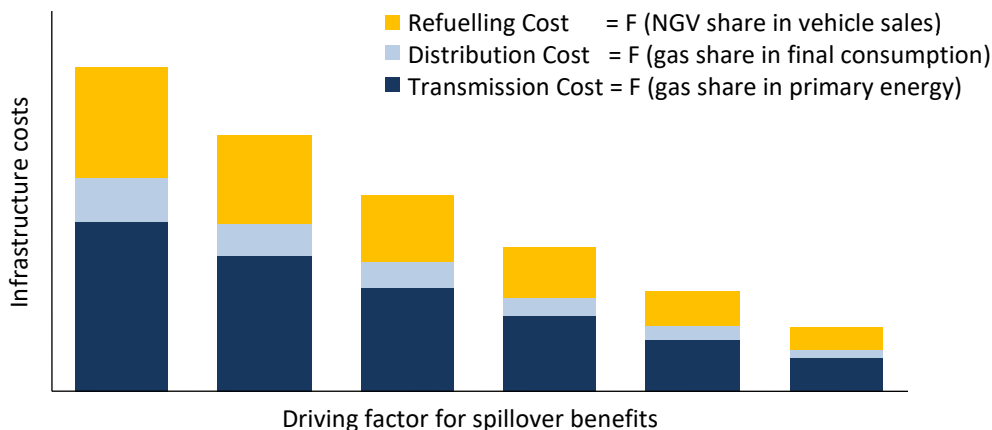
As a second step, the model simulates the cost effectiveness of a conventional ICE vehicle against other competing alternative options. The simulation is guided by the use of a Weibull function. Alternative powertrains for medium- and heavy-duty trucks have been implemented in the GEC Model: fuel cell, battery electric and plug-in hybrid electric.

The road freight module utilises regional analysis to assess freight activity, taking into account the geographical and economic characteristics of the countries under examination. This enhanced module provides projections by factoring in economic indicators and the dynamics of fuel prices. It provides valuable insights into both the future trajectory of freight activity and the evolving occupancy factors for different truck size categories.

Finally, based on projections of the average fuel consumption of new vehicles by vehicle type, the road transport model calculates average sales and stock consumption levels (on-road and test cycle) and average emission levels (in grammes of CO₂ per kilometre) over the projection period. The model takes into account second-hand market trends and assesses the impact of policies on fuel economy improvements in countries importing vehicles from regions with ambitious fuel economy goals. It further determines incremental investment costs relative to other scenarios and calculates implicit CO₂ prices that guide optimal allocation of abatement in transport.

To assess the problems created due to chicken-and-egg-type situations when it comes to the deployment of those alternative fuels in transport that require a dedicated refuelling infrastructure, and to better reflect potential spill-over effects of the use of such alternative fuels in other sectors of the energy system, the GEC Model has dedicated sub-models for covering refuelling infrastructure. In principle, the modules seek to quantify the costs and benefits of increased infrastructure availability for transmission and distribution of these alternative fuels. In essence, the relationship of these spill-over benefits can be illustrated as in Figure 3.8.

Figure 3.8 ▶ Refuelling infrastructure cost curve (illustrative)



IEA. CC BY 4.0.

Note: NGV = natural gas vehicle.

In the case of electric vehicles, availability of a robust transmission and distribution grid is less of an issue, especially in advanced economies, thanks to the already existing widespread use of electricity in different end-use sectors (especially buildings). However, the availability of electric recharging infrastructure is one of the important constraints in this case, and hence it is important to determine how a reduction in refuelling costs could influence the possibility for oil substitution in road transport. Therefore, the EV sub-module assesses the cascading effect of an increased share of electric vehicles in overall vehicle sales on bringing down the refuelling costs. Detailed cost curves were prepared outlining the reduction of refuelling costs with the increase in overall vehicle stock of electric vehicles. These cost curves were provided as an exogenous input to the model, so as to continuously adjust the refuelling costs as the share of EV sales rises in the future.

EV supply equipment (EVSE or EV charger) stock is also projected by vehicle category. For light-duty vehicles, the number of public chargers is calibrated to start from the historical trends of EVSE/EV, where relevant. The share of slow and fast chargers is also calibrated to historic data, where available. The pace of the deployment of private and public charging infrastructure is informed by data on the share of households living in single-family houses, the availability of EV charging infrastructure in private and multi-family dwellings, and the current provision and level of publicly available charging ports and stations.

In general, the public EVSE-to-EV ratio is projected such that as the EV stock share increases, the required kW of public charging capacity per EV decreases to reflect that the system becomes better optimised as the market matures. For buses and trucks, the share of electricity demand met through opportunity or public chargers is projected by segment. The required number of public chargers is then estimated based on an assumed mix of chargers with different charging capacities.

Hydrogen fuel consumption is used to estimate the number of hydrogen refuelling stations (HRS) needed to meet demand. Station capacities are modelled to evolve (grow) over time, with different size limits set based on the target vehicles being served. For example, HRS for trucks have higher maximum capacities than stations to serve the light-duty vehicle market. Though, of course, some stations will have dual pressure dispensing and serve different vehicle markets. However, the modelling also differentiates utilisation rates by target vehicle category, where stations for fleets of buses and trucks are expected to have higher average utilisation rates than those for light-duty vehicles. Thus, the stock of HRS required to serve FCEVs is:

$$HRS\ Stock = \sum \frac{F_i}{C_i \times U_i}$$

Where:

- i represents the vehicle category
- F_i represents the hydrogen fuel demand (kg H₂/year) of vehicle category i
- C_i represents the average nameplate capacity (kg H₂/year) of HRS serving primarily category i
- U_i represents the average utilisation rate (%) of HRS serving primarily category i

Rail

The rail module builds on a historical database that covers 5 different rail types and 4 fuels across more than 130 countries. Key parameters include energy intensity, activity, mileage, stock, load/occupancy factor and track length and utilisation. Three different scrappage curves are used to derive historical train sales numbers per rail type and fuel.

In the database, rail vehicle and passenger/freight activity are calibrated across urban (metro and light-rail) and non-urban (conventional and high-speed passenger rail, and freight rail), for diesel, electricity and coal, to match the energy balances at the country level.

Rail modelling builds upon databases of urban rail activity (metro and light-rail) from the International Association for Public Transport and the Institute for Transportation Development and Policy, including databases of urban rail infrastructure. It further builds upon data from the International Railway Union and the JRC on intercity (conventional), high-speed, and freight rail activity, stock, and infrastructure. Rail activity per type is calibrated to the data collected from government statistics, the World Bank, United Nations Economic Commission for Europe, and International Railway Union. Electrification and hydrogen penetration rates in conventional passenger and freight rail is informed by current and announced rail projects and targets, as well as regulatory, fiscal, investment and climate policies that vary by scenario.

Energy intensity, occupancy/load factor, mileage and track utilisation are projected with consideration of GDP/capita and the historical performance, and vary by scenario. Activity projections per rail type for non-high-speed rail (non-HSR) are calibrated with the previous rail module, while high-speed rail (HSR) activity projections are mainly informed by the planned line buildouts, GDP per capita assumptions and historical track utilisation factors. The impact of behavioural change in the rail module is differentiated between HSR and non-HSR, also varying by scenario. For HSR, activity growth resulting from behaviour change considers aviation-to-rail shifting informed by countries' Nationally Determined Contributions (NDCs). For non-HSR, activity growth due to behavioural change is based on historical track utilisation and rail passenger activity per-capita data, as well as the role of rail in the NDCs.

Aviation

Aviation fleet and passenger activity is calibrated at a country/regional level to match domestic and international energy demand for jet kerosene. Aviation modelling builds upon collaboration with researchers at University College London (UCL), who have developed and maintain the open-source Aviation Integrated Model (AIM). Key features of AIM preserved in IEA modelling include:

- Operational and technical potential for energy intensity improvements based on detailed, origin-destination modelling of aircraft and airport operations and airframe-propulsion systems, with stock-modelling and techno-economic modelling, in the framework of iterative cost minimisation.
- Regional and airport-resolution long-term price and GDP demand elasticities aligned with IATA and other authoritative studies enabling credible and high-resolution activity projections.

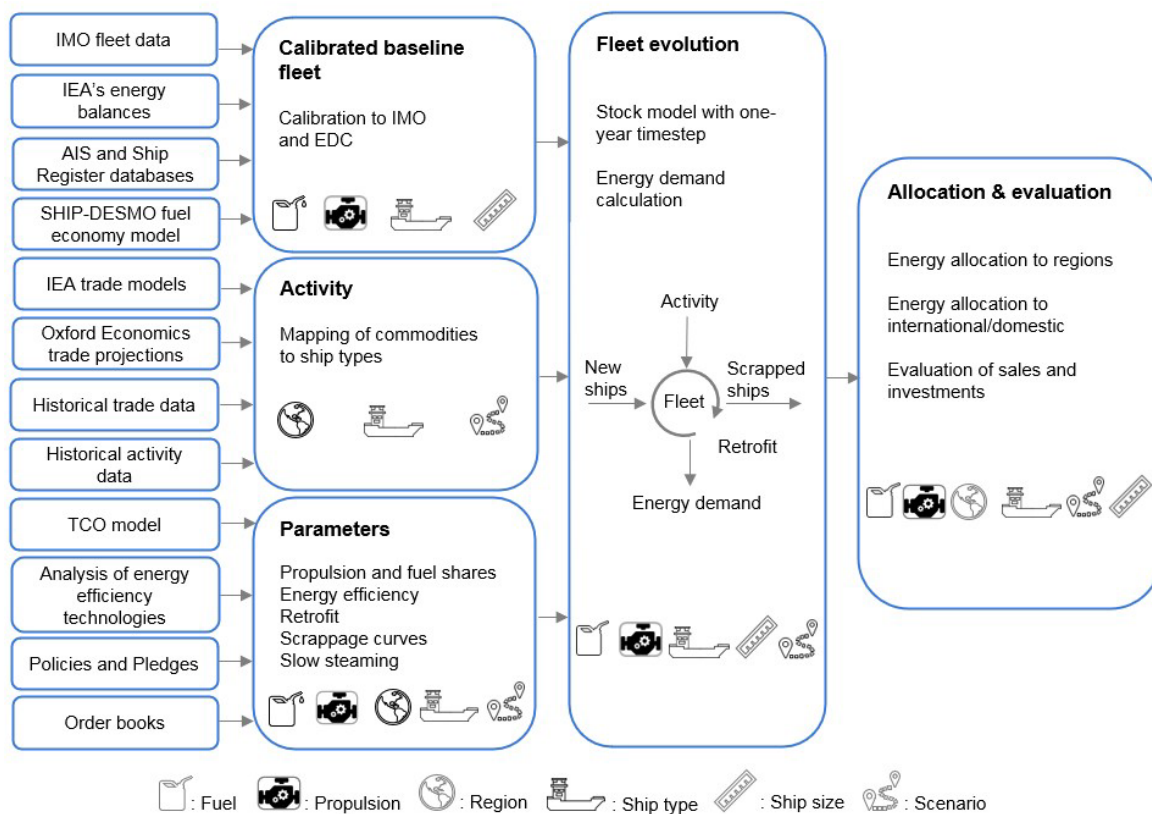
Projections integrate the main features of detailed iterative cost minimisation modelling using AIM with “top-down” projections of fuel consumption by other aviation activities (non-passenger activity, such as dedicated

cargo). Further elaboration builds upon IEA techno-economic modelling of energy supply and fuels transformation modelling, as well as elaborations of policy targets and demand-side management strategies.

Shipping

The methodology of the bottom-up model for shipping energy demand is illustrated in Figure 3.9. Activity projections, a calibrated baseline fleet, and scenario-specific parameters are inputs into a dynamic stock model that calculates the evolution and the energy demand of the global shipping fleet by ship type, propulsion, and fuel. This energy demand is subsequently allocated across regions and allocated to either the international or the domestic shipping sectors.

Figure 3.9 ▶ Shipping model methodology



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Note: IMO: International Maritime Organization, AIS: Automatic Identification system, TCO: total cost of ownership.

The characteristics of the baseline shipping fleet, including distributions of ship type, size, and age, are sourced from the Ship Register, accessed via the UN big data platform (United Nations, 2024). The model explicitly includes the following ship types: container ships, bulk carriers, oil tankers, general cargo, liquefied gas tankers, and chemical tankers. These ship types accounted for 75% of global shipping GHG emissions in 2018 (IMO, 2021), while the remainder of the fleet is categorised as “other ships.” Automatic Identification System (AIS) data, also obtained through the UN big data platform (United Nations, 2024), is used to derive distributions of speed, average distance travelled, days spent at sea, load factors and for deriving shares of international versus domestic voyages per ship type and size. Energy efficiencies (intensities) of ships in the existing stock are calculated with the SHIP-DESMO model (Technical University of Denmark, 2016). The resulting energy demand is then calibrated to align with IMO energy consumption data by ship type (IMO, 2021) and IEA’s 2024 Energy Balances, which also determines the international/domestic split of energy demand. In IEA energy balances,

domestic navigation energy demand includes fuels delivered to vessels of all flags not engaged in international navigation. This excludes fuel used for ocean, coastal, and inland fishing, and military consumption. International marine bunkers, on the other hand, covers fuel quantities delivered to ships of all flags engaged in international navigation, and excludes fishing vessels and military forces. The domestic/international split is determined based on port of departure and port of arrival, and not by the flag or nationality of the ship (IEA, 2024g).

Activity projections are derived from a newly developed bottom-up tool that uses a variety of data sources. For historical shipping activity, trade data by Oxford Economics Trade Prism (Oxford Economics, 2024b) are used and combined with CEPII BACI data (CEPII, 2010) to enhance data granularity and geographical coverage. Historical data is aligned with UNCTAD data on international shipping activity (United Nations, 2023). For activity projections, IEA internal energy trade projections for energy (oil, gas, coal, hydrogen and alternative fuels) and trade flows for key materials and clean energy technologies from IEA's MaT model (see forthcoming ETP-24 publication (IEA, 2024b) for more information) are used to compound overall international shipping activity so that internal consistency by scenario is ensured. For commodities outside the scope of IEA trade modelling (accounting for about one-third of traded mass in 2025 projections), Oxford Economics forecasts are used. Trade flows of commodities are allocated to ship types, determining the activity for all explicitly modelled ships. Other ships are treated with a simplified approach: activity is estimated through econometric scaling.

Input parameters to the model are informed by several sources, including a total cost of ownership (TCO) model, an analysis of existing energy efficiency technologies and their impact on different ship types, order books for new ships, and policy measures and pledges. The TCO model identifies the most cost-effective propulsion and fuel options for various ship types and sizes.

A dynamic stock model calculates the annual evolution of the global shipping fleet, where the necessary stock of each ship type is derived based on the shipping activity, average distance travelled, and size distribution. Scrappage curves determine ship retirements based on the age distribution of the fleet, and new ships are added to ensure activity projections can be met. Eligible ships, determined based on ship type, ship size and age criteria, are either upgraded with various energy efficiency measures or retrofitted with alternative propulsion systems. The model then calculates energy demand based on energy consumption drivers (size, speed, load factor, distance travelled) and ship efficiencies. For non-explicitly modelled ships ("other ships"), energy efficiency and fuel share inputs are directly applied to calculate energy use by fuel type.

The global energy demand by ship and propulsion type is then allocated across regions and sectors (international or domestic). Regional allocation is based on historical and extrapolated energy demand, and thus reflects where bunkering occurs.

Behavioural change analysis

Several analyses regarding behavioural change in transport have been carried out:

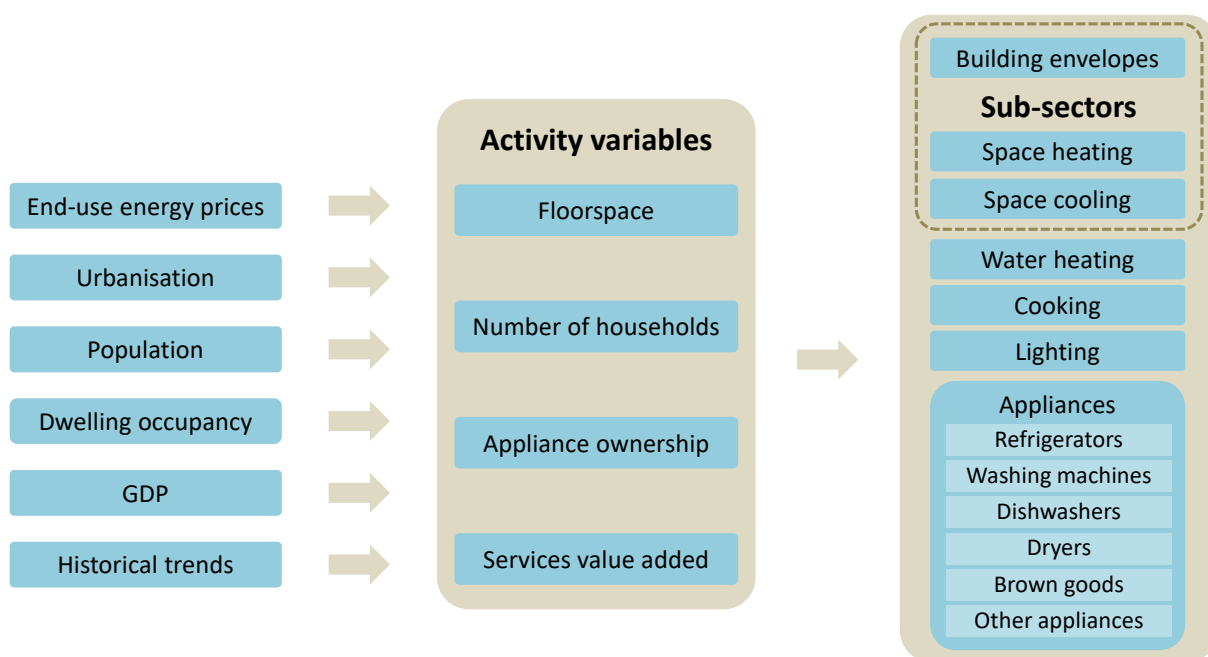
- Ex-post analysis on the impact of behavioural change on the aviation sector has been developed. Historical data (OAG, AIM from UCL) has been used to disaggregate aviation activity per person and distance. Changes in occupancy factors have been assumed to assess the impact of behavioural change in oil demand.
- Both commercial (IHS Markit, Jato Dynamics, Marklines) and in-house (Global Fuel Economy Initiative, historical road database) datasets have been used to perform in-depth analysis by country on the rise of sport utility vehicles (SUVs). Based on an analysis of historic trends, a moderate growth of SUVs is projected in the STEPS on a global scale.
- The car market is analysed using multiple sources (Marklines, EV Volumes, etc.), estimating the future evolution of car sales. Based on a stock model, a change in car sales volume due to both new purchases and replacements is estimated. Econometric functions have been applied to project the future trend.

- During the Covid-19 pandemic, data showed a shift from public transport to private vehicles due to health concerns. Publicly available reports, including a survey by Ipsos, were used to estimate the mobility needs that were covered by bicycles or private cars. Assumptions differ by GEC Model region, depending on the accessibility of bikes, and the impact on oil demand due to this modal shift was estimated.
- With regards to the impact of working from home, a literature review has been carried out on the average commuting distance by transport mode for key GEC Model regions. These data have been extrapolated to all regions. Assuming the maximum potential for the workforce to work from home (i.e. 20% by 2030), the impact of working from home on oil demand was assessed.

3.3 Buildings

The buildings sector module of the GEC Model is subdivided into the residential and services sectors, with both having similar structures (Figure 3.10). Population, GDP, climate and dwelling occupancy inform the activity variables, which include floorspace, appliance ownership, number of households (for the residential sector) and value added (for the services sector).

Figure 3.10 ▶ Structure of the buildings demand module



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Within the residential and services sectors, energy demand is subdivided into six standard end uses in buildings, namely space heating, water heating, appliances, lighting, cooking and space cooling. Appliances are divided into four main categories: refrigeration (refrigerators and freezers), cleaning (washing machines, drying machines and dishwashers), brown goods (televisions and computers); and other appliances. Space cooling comprises gas chillers, air conditioners, district cooling, solar cooling and fans. All listed end uses within each sector are modelled individually, with final energy consumption being projected from the base year for each end-use in three steps.

The first step is calculating the demand for an energy service, i.e. the useful energy demand, based on activity variables. The basic concept for this step is:

$$\text{End use service demand} = \text{Activity variable} \times \text{intensity}$$

Activity variables refer to the main drivers of energy service demand (see above). Intensity refers to the amount of energy service (e.g. space heating) needed per unit of the activity variable (e.g. floorspace). The activity variables are projected econometrically, based on historical data and linking to socio-economic drivers including GDP, population, urbanisation rates, and access rates to modern energy. For each end-use, the intensity variable is projected using historical intensity and adjusting, for each projection year, to the change in average end-user fuel prices (based on price elasticities) and the change in average per-capita income (based on income elasticities) over time.

In the case of space heating and space cooling, intensity projections are also adjusted for historical variations in temperature, and the improvements in buildings energy performance associated with new construction or renovation standards.

Historical energy demand for space heating and space cooling, as well as historical heating and cooling degree-day data are combined to normalise projections of space heating and space cooling energy demand, removing the impacts of year-on-year volatility on energy service demand. The impact of climate change on space heating and space cooling demand is accounted for in the model as well, based on the anticipated change in heating and cooling degree-days due to climate change in each region and under each scenario's temperature pathway. These projections are based on IEA analysis derived from relevant projections published in the IPCC Working Group I Interactive Atlas.

Space heating and space cooling service demand is computed for buildings upon their construction, based on the building's average energy efficiency performance at the time of construction. New buildings in the model are constructed as either non-compliant with building energy codes, compliant, or zero-carbon-ready buildings. This choice, as well as the region and the year of construction, influences the building's energy service demand. The energy service demand of a building in the model can also be influenced by retrofitting: an existing building can be retrofitted to improve its energy performance, so that the building complies with existing regulation or becomes zero-carbon-ready. The projections of the shares of each type of new building and retrofit depend on the policy assumptions underlying each scenario. Retrofitting a building extends its lifetime, influencing both the need for new constructions and the associated demand for construction materials.

The total energy service demand to be met by space heating or cooling equipment is therefore the sum of the service demand across the different vintages of buildings, determined by the year of construction, and across the five categories of buildings (non-compliant, compliant, zero-carbon-ready, retrofit to compliant, retrofit to zero-carbon-ready). Improvements in the performance of building envelopes (either via more efficient new constructions or via retrofits) shift them from one category to another and thereby reduce the total energy service demand for space heating and space cooling that remains to be met by heating or cooling equipment.

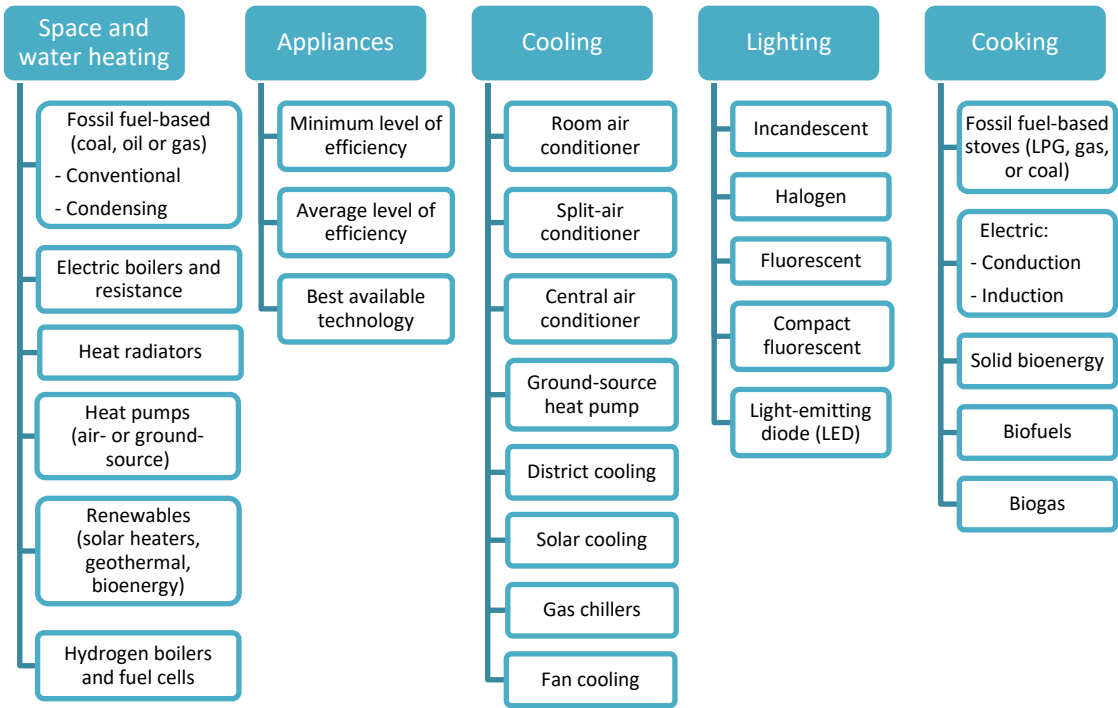
The second step is choosing the technologies to supply the end-use service demand. For each end-use, there is a detailed set of technologies available in the model, as shown in Figure 3.11. Most of the technology options are modelled in tiers, representing varying levels of energy efficiency and associated investment costs. Additionally, there is a possibility to switch fuels and technologies, whereby heat pumps could be used for space heating instead of gas boilers, for example. Within the residential sector, additional detail regarding bioenergy allows for more accurate modelling of the historical and projected use of biogas digesters to meet home energy needs, as well as the use of bioethanol and other liquids in cookstoves and household heating equipment.

Over the projection horizon, the technology choice is based on technologies' relative costs, their efficiencies, and any relevant constraints in the region considered. Technology shares are allocated by a Weibull function that accounts for each technology's costs per unit of service demand supplied, which includes investment costs, operation and maintenance costs and fuel costs. For example, the relative economic competitiveness of a heat pump versus a gas boiler for space heating differs depending on the building's service demand for heating, which impacts the importance of investment costs relative to operational costs. The model routine allocates different

technologies to satisfy the additional service demand each year over the model horizon. This allocation is subject to upper and lower boundaries, reflecting real-world constraints such as technology availability, policies and market barriers.

To assess and update equipment and appliance efficiency, and related costs, a large number of companies, experts and research institutions at the national and international levels, including IEA Technology Collaboration Programmes, are regularly contacted. The assessment was also supported by an initial extensive literature review to catalogue technologies that are now used in different parts of the world and to judge their probable evolution (Econoler, et al., 2011; Kannan, et al., 2007; Waide, 2011; LBNL, 2012; GBPN and CEU, 2012).

Figure 3.11 ▶ Major categories of technologies by end-use sub-sector in buildings



IEA. CC BY 4.0.

The third step is calculating total final energy consumption in the residential and service sector based on the efficiencies of existing and new building equipment. Efficiency represents the amount of energy needed to meet a unit of service demand, and thus represents the technical performance of the equipment or appliances. Final energy consumption in the buildings sector is a summation of the sub-sectoral energy consumed by the total technology stock, which includes the historical (declining) stock of appliances and equipment, and the new technologies added every year over the model horizon by the technology allocation routine.

$$Final\ energy\ consumption = \frac{1}{Efficiency} \times End\ use\ service\ demand$$

The impact of behavioural change is integrated at this point, with both the energy use and energy service demand per technology adjusted to reflect scenario assumptions on the breadth and depth of behavioural change in the buildings sector.

Model outputs in terms of energy demand by technology, the number of technology units deployed, buildings constructed or retrofitted, are all used to calculate investments and energy expenditure. CO₂, other GHG emissions and material needs (steel, cement and aluminium) related to the buildings sector are also calculated.

The buildings module is directly linked to the energy access module in order to take into account the growth of electricity and of alternative fuels or stoves for cooking (see Section 11).

Desalination

Energy consumption for the desalination of water is modelled within the service sector module of the buildings model. Data on the geographical distribution of desalination plants is updated on a regular basis from GWI DesalData, including information on technology, feedwater, plant size and spending area. Based on the fuel split and energy intensity of different desalination-technologies, projections on the energy consumption for desalination needs are included in IEA scenarios. The modelling of the desalination sector takes into account varying policy-landscapes as well as different global surface temperatures by scenario.

Data centres

Energy use in data centres is also modelled within the service sector module of the buildings model. Data centres' electricity consumption is classified under the services sector, following the International Standard Industrial Classification of All Economic Activities (ISIC), and is further divided into cooling, appliances, and auxiliary equipment.

Behavioural change

Behavioural changes modelled within the buildings module include lower indoor air temperature settings, lower use of air conditioning, use of line-drying, efficient use of lighting and appliances, optimised boiler settings and cool washing. A literature review was carried out to assess the impact on energy consumption. The potential is estimated to assess the total impact and the resulting decrease in buildings sector emissions.

The impact of working from home is analysed based on a literature review on how much working from home increases residential energy consumption in key GEC Model regions. Data from the literature review have been extrapolated to all regions and the impacts on energy demand estimated by fuel. The maximum potential for working from home was assessed on a country-by-country basis to inform the impact on residential energy consumption.

3.4 Hourly electricity demand and demand-side response

Understanding the hourly, daily and seasonal evolution of electricity demand is critical for accurate modelling of electricity systems, including the assessment of electricity system flexibility needs and the role of demand-side response.

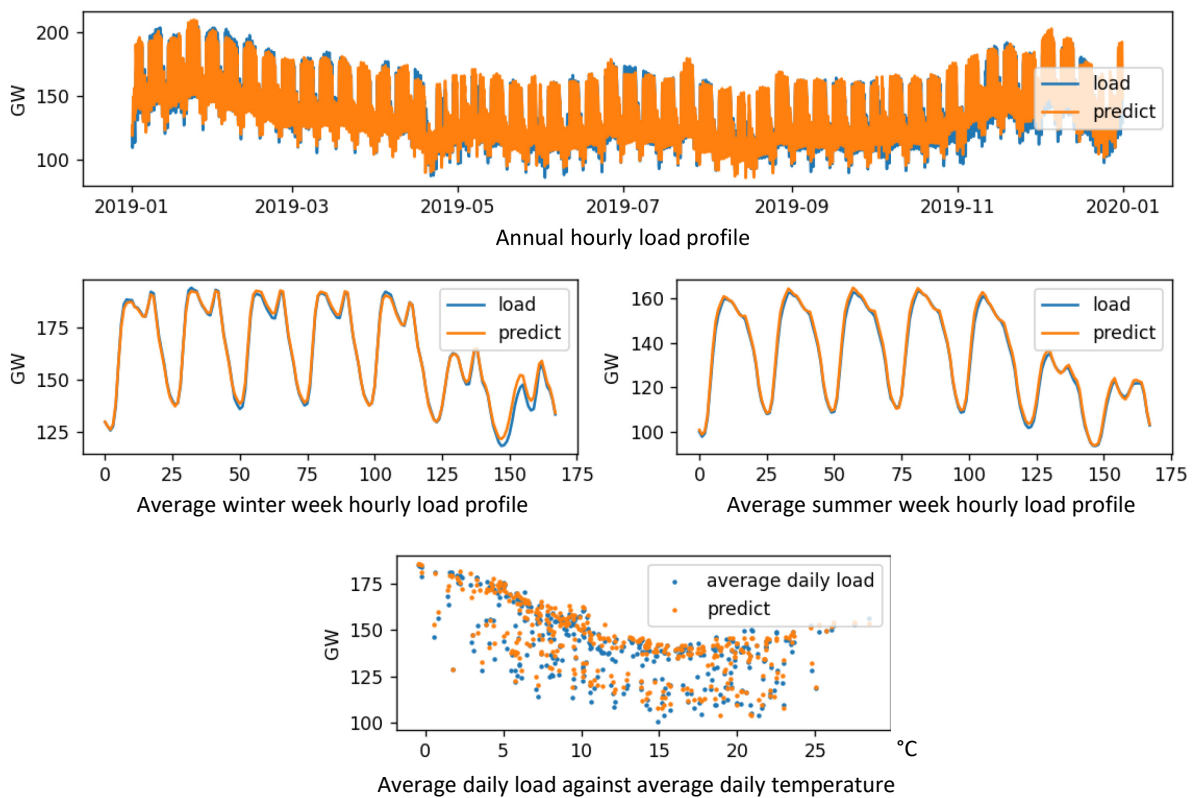
Modelling of hourly electricity demand is undertaken at an end-use level. This allows the model to reflect the impact of the full scope of demand-side integration measures: electrification and energy efficiency impact the annual demand for end uses, while demand-side response, including load shifting and shedding, affects demand at a more temporally granular level. Modelling hourly load requires assessment of the hourly load profile for each end-use within each sector, residential and services (e.g. space heating, water heating), industry (e.g. steel, chemicals), transport (e.g. road, rail) and agriculture. Load curves are assessed for a full year at the hourly resolution.

Load curve parameters are derived from historical data. A statistical analysis is conducted on historical hourly demand (IEA, 2024g) and heating and cooling degree-day timeseries (IEA, 2024h). The hourly load dependency to calendar and weather variables is extracted from regression parameters. The weather variables are weighted by population, and temperature thresholds activating cooling and heating demand are determined based on the load response to temperature variations. The statistical analysis is conducted on as many historical years as

available, considering the structural changes in electricity demand over time and temporary changes in electricity consumption patterns, such as during pandemic containment measures.

Average weekly profiles for heating, cooling and non-thermosensitive load are derived from this analysis, along with additional parameters such as the average demand per week of the year. This thermosensitivity analysis allows for the simulation of a region’s electricity load curve with a very high level of confidence, considering the impact of variations in weather, most notably temperature.

Figure 3.12 ▶ Thermosensitivity analysis for hourly load curve assessment



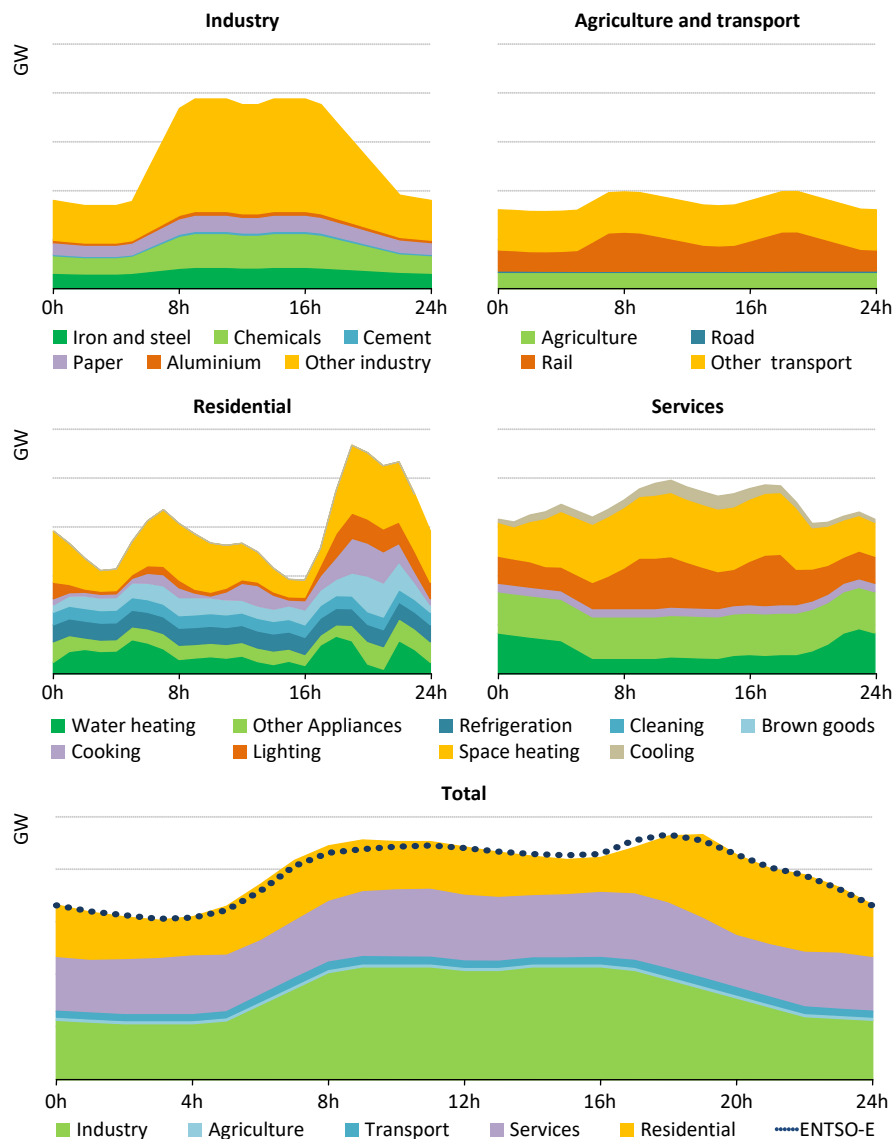
IEA. CC BY 4.0.

Individual hourly load curves for each electricity end use are generated based on the thermosensitivity analysis, research, and survey data where available. Total space heating and cooling profiles are split between residential and services end uses depending on the hourly activity in each sector. Load curves for other end uses are informed by literature and adjusted to match the total non-thermosensitive profile of the region. Lighting hourly electricity demand is projected based on daylight times and solar insolation levels. An example of the load disaggregation per end use is displayed in Figure 3.13.

Eventually, load profiles are scaled to the annual end-use demand in the projected year, as simulated in the GEC Model. The hourly load profile can be generated for different weather conditions, by varying the historical temperature timeseries used as an input. This allows for an assessment of the impact of weather on peak demand and flexibility needs over multiple weather years.

The hourly load generation is either performed at the country level or at the GEC region level. The hourly load model covers more than 75% of world electricity consumption in 2023, including, among others, China, India, the European Union, the United States and Japan.

Figure 3.13 ▶ Illustrative load curves by sector for a weekday in February in the European Union compared to the observed load curve by ENTSO-E for 2014



IEA. CC BY 4.0.

Note: European Network of Transmission System Operators for Electricity (ENTSO-E) represents the aggregated load curve for all countries in the European Union.

Sources: IEA analysis based on ENTSO-E (2024).

Modelling the role and potential of demand-side response requires assessment of the share of demand that is flexible in each end use. This share is the product of three flexibility factors, shiftability, controllability and acceptability (Olsen, 2013):

- **Shiftability:** Share of the load of each end-use that can be shed, shifted or increased by a typical demand-response strategy.
- **Controllability:** Share of the load of each end use which is associated with equipment that has the necessary communications and controls in place to trigger and achieve load sheds/shifts.

- **Acceptability:** Share of the load for a given end-use which is associated with equipment or services where the user is willing to accept the reduced level of service in a demand-response event in exchange for financial incentives.

This framework enables scenarios to consider demand flexibility from various technologies and at varying levels of social acceptability.

Demand response is included in an hourly electricity model that jointly simulates the dispatch of generation assets, storage, interconnections, and demand response to minimise total operating system costs (see section 4.4 for a description of the hourly model). Demand-response activation considers the flexibility potential (in GW), the maximum shifting or shedding duration (in hours) and the flexibility activation cost. For transport, additional constraints are developed in the hourly model to reflect the unavailability of unplugged or fully charged EVs for load management.

Electricity generation and heat production

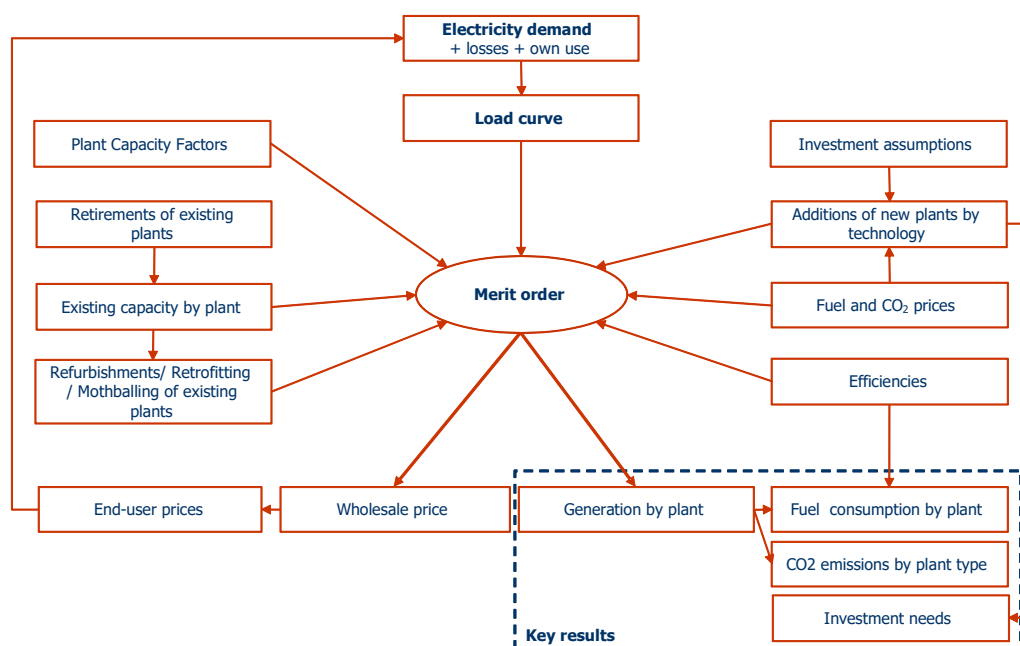
Based on electricity demand, which is computed in all end-use sectors (described in Section 3) and other energy transformation sectors – notably hydrogen produced via electrolysis (Section 5), the power generation module calculates the following:

- Amount of new generating capacity needed to meet demand growth and cover retirements and maintain security of supply.
- Type of new plants to be built by technology.
- Amount of electricity generated by each type of plant to meet electricity demand, cover transmission and distribution losses and own use.
- Fuel consumption of the power generation sector.
- CO₂ emissions from the combustion of fossil fuels and non-renewable wastes, including reductions from the use of carbon capture, utilisation and storage (CCUS) technologies.
- Transmission and distribution network infrastructure needed to meet new demand and replace retiring network assets.
- Wholesale and end-use electricity prices.
- Investment associated with new generation assets and network infrastructure.

4.1 Electricity generation

The structure of the power generation module is outlined in Figure 4.1. The purpose of the module is to ensure that enough electrical energy is generated to meet the annual volume of demand in each region, and that there is enough generating capacity in each region to meet the peak electrical demand, while ensuring security of supply to cover unforeseen outages.

Figure 4.1 ▶ Structure of the power generation module



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The model begins with existing capacity in each region, which is based on a database of all world power plants. The technical lifetimes of power plants are assumed to range between 45 and 60 years for existing fossil-fuel plants and nuclear plants (unless otherwise specified by government policies). The lifetimes of wind and solar PV installations are assumed to have a distribution centred around 25 years, ranging from 20 to 30 years; hydropower projects 50 years; and bioenergy power plants 25 years.

4.1.1 Capacity additions

The model determines how much new generation capacity is required annually in each region by considering the change in peak demand compared to the previous year, retirements of generation capacity during the year, and any increase in renewable capacity built as the result of government policy. Installed generating capacity must exceed peak demand by a security-of-supply margin; if this margin is not respected after changes in demand, retirements, and renewables additions, then the model adds new capacity in the region. In making this calculation, the model takes into account losses in transmission and distribution networks and electricity used by generation plants themselves.

Because of the stochastic nature of the output of variable renewables such as wind and solar PV, only a proportion of the installed capacity of these technologies can be considered to contribute to the available generation margin. This is reflected in the modelling by the use of a capacity credit for variable renewables. This capacity credit is estimated from historical data on hourly demand and hourly generation from variable renewables in a number of electricity markets, and it reflects the proportion of their installed capacity that can reliably be expected to be generating at the time of peak demand.

When new plants are needed, the model makes its choice between different technology options on the basis of their regional value-adjusted levelised cost of electricity (VALCOE), which are based on the levelised cost of electricity (LCOE), also referred to as the long-run marginal cost (LRMC). The LRMC of each technology is the average cost of each unit of electricity produced over the lifetime of a plant, and is calculated as a sum of levelised capital costs, fixed operation and maintenance (O&M) costs, and variable operating costs. Variable operating costs are in turn calculated from the fuel cost (including a CO₂ price where relevant) and plant efficiency. Our regional assumptions for capital costs are taken from our own survey of industry views and project costs, together with estimates from the Nuclear Energy Agency (NEA) and the IEA (2010). The weighted average cost of capital (pre-tax in real terms) is assumed to be 9% in the OECD and 8% in non-OECD countries unless otherwise specified, for example with revenue support policies, onshore wind and utility-scale solar PV at 4-7% (see financing costs section below), and offshore wind at 5-8% depending on the region.

The LRMC calculated for any plant is partly determined by their utilisation rates. The model takes into account the fact that plants will have different utilisation rates because of the variation in demand over time, and that different types of plants are competitive at different utilisation rates. (For example, coal and nuclear tend to be most competitive at high utilisation rates, while gas and oil plants are most competitive at lower utilisation rates).

The specific numerical assumptions made on capital costs, fixed O&M costs, and efficiency can be found on the GEC Model website: <https://www.iea.org/reports/global-energy-climate-model/techno-economic-inputs>.

The levelised cost module computes LRMCs (or LCOEs) for the following types of plant:

- Coal, oil and gas steam boilers with and without CCUS.
- Combined-cycle gas turbine (CCGT) with and without CCUS.
- Open-cycle gas turbine (OCGT).
- Integrated gasification combined-cycle (IGCC).
- Oil and gas internal combustion.
- Fuel cells.
- Bioenergy with and without CCUS.

- Geothermal.
- Wind onshore and offshore.
- Hydropower (conventional).
- Solar photovoltaics.
- Concentrating solar power.
- Marine.
- Utility-scale battery storage.

Regional LRMCs are also calculated for nuclear power but additions of nuclear power capacity are subject to government policies.

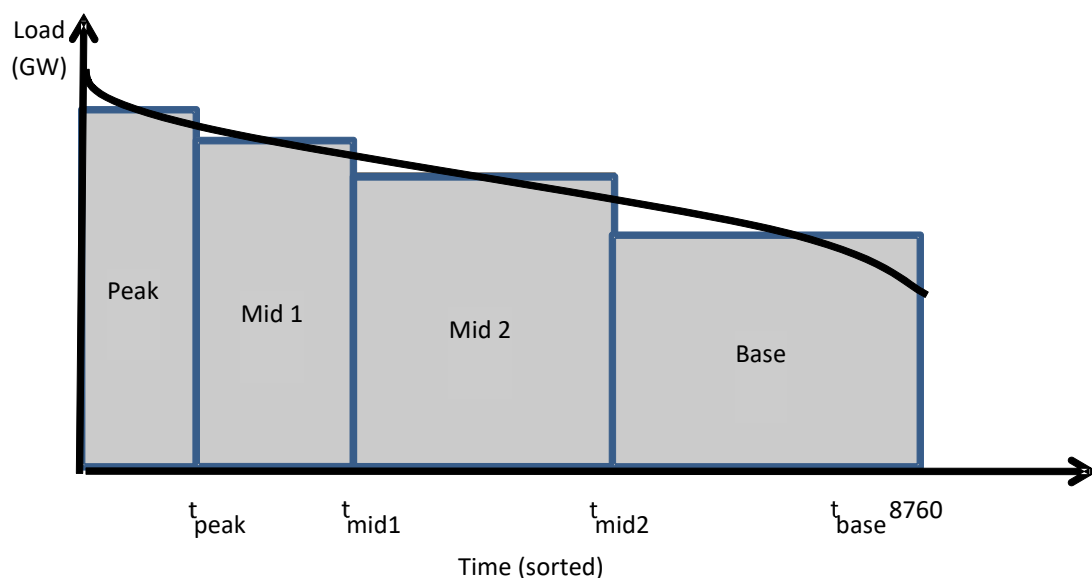
4.1.2 Generation volumes

For each region, the model determines the generation from each plant based on the capacity installed, the marginal cost to produce electricity and the level of electricity demand. Demand is represented as four segments:

- baseload demand, representing demand with a duration of more than 5 944 hours per year
- low-midload demand, representing demand with a duration of 3 128 to 5 944 hours per year
- high-midload demand, representing demand with a duration of 782 to 3 128 hours per year
- peakload demand, representing demand with a duration of less than 782 hours per year.

This results in a simplified four-segment load-duration curve for demand (Figure 4.2). This demand must be met by the available power capacity of each region, which consists of variable renewables – technologies like wind and solar photovoltaics (PV) without storage, whose output is driven by weather – and dispatchable plants (generation technologies that can be made to generate at any time except in cases of technical malfunction). To account for the effect of variable renewables on wholesale prices, the model calculates the probable contribution of variable renewables in each segment of the simplified load-duration curve. Subtracting the contribution of renewables from each segment in the merit order leaves a residual load-duration curve that must be met by dispatchable generators.

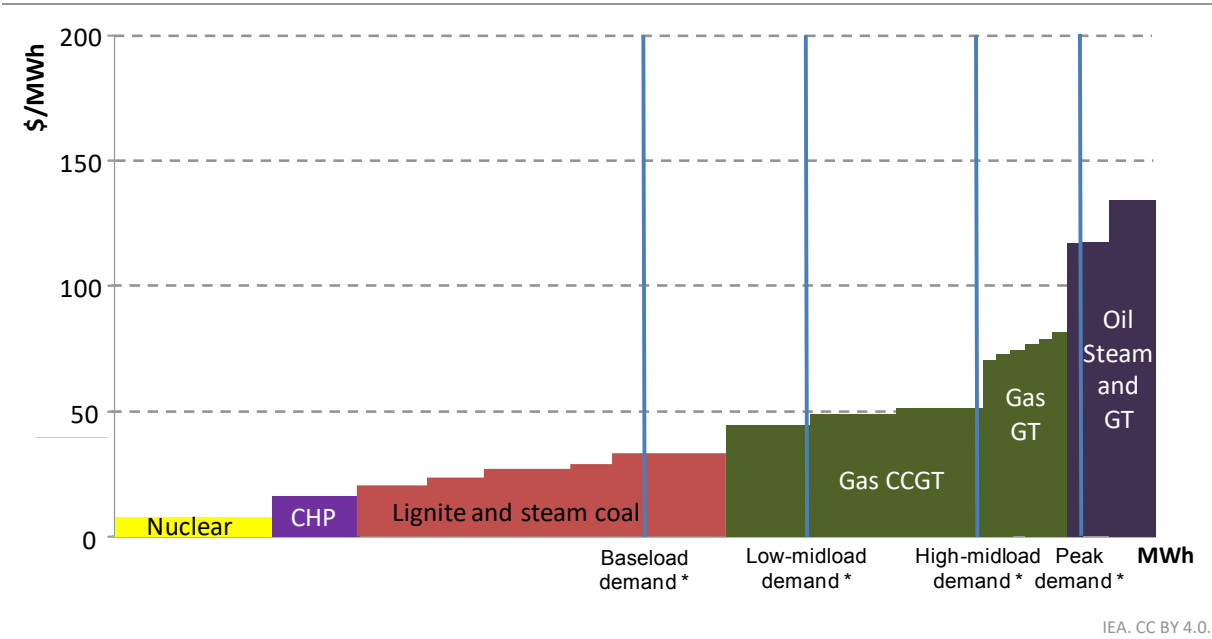
Figure 4.2 ▶ Load-duration curve showing the four demand segments



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The model subtracts from the demand in each segment any generation coming from plants that must run – such as some combined heat and power (CHP) plants and desalination plants – and also generation from renewables. For generation from variable renewables, the amount of generation in each demand segment is estimated based on the historical correlation between generation and demand. The remainder of the demand in each segment must be met by production from dispatchable plants. The model determines the mix of dispatchable generation by constructing a merit order of the plants installed – the cumulative installed generation capacity arranged in order of their variable generation costs – and finding the point in the merit order that corresponds to the level of demand in each segment. As a result, plants with low variable generation costs – such as nuclear and lignite-burning plants in the example of Figure 4.3 – will tend to operate for a high number of hours each year because even baseload demand is higher than their position in the merit order. On the other hand, some plants with high variable costs, such as oil-fired plants, will operate only during the peak demand segment.

Figure 4.3 ▶ Example merit order and its intersection with demand in the power generation module



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Notes: CCGT = Combined-cycle gas turbine; CHP = combined heat and power; GT = gas turbine. Demand here means demand net of generation by “must run” plants such as desalination and some CHP plants, and net of generation by renewables.

4.1.3 Calculation of the capacity credit and capacity factor of variable renewables

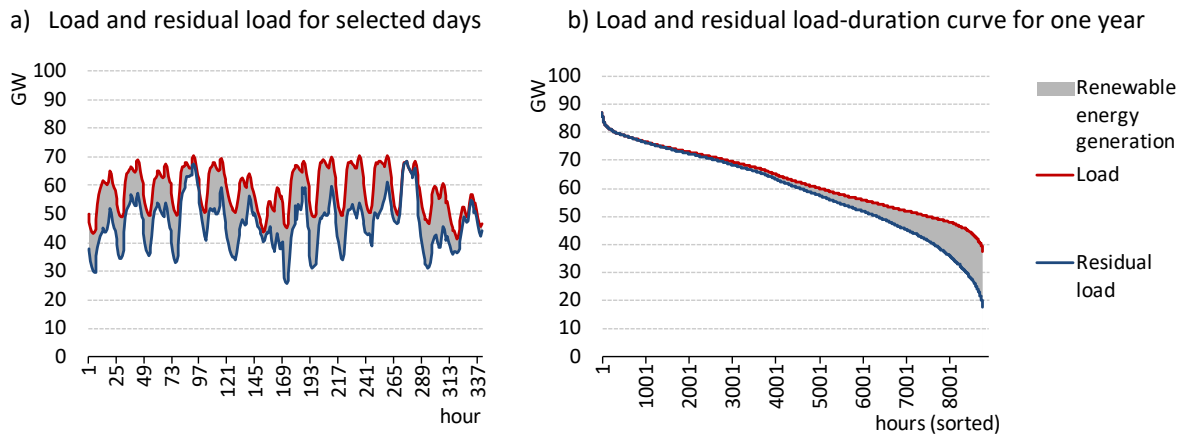
Power generation from weather-dependent renewables such as wind and solar power varies over time and the characteristics of the power supply from variable renewables have to be taken into account for the decisions on dispatch and capacity additions of the remaining, mostly dispatchable power plants. The effect of all variable renewables (solar PV, concentrating solar power [CSP] without storage and wind on- and offshore) is taken into account via the capacity credit and the capacity factor in each load segment.

The capacity credit of variable renewables reflects the proportion of their installed capacity that can reliably be expected to be generating at the time of high demand in each segment. It determines by how much non-variable capacity is needed in each load segment. The capacity factor gives the amount of energy produced by variable renewables in each load segment and determines how much non-variable generation is needed in each segment.

Both capacity credit and capacity factor are calculated based the comparison between the hourly load profile and the wind and solar supply time series, derived from meteorological data. To quantify the effects of variable renewables, the hourly load profile is compared to the hourly residual load, being the electricity load after

accounting for power generation from variable renewables (Figure 4.4). By sorting the residual load, the levels of average and maximal demand per load segment can be determined. The difference between the load levels of the normal load and the residual load gives the impact of variable renewables on the power generation and capacity needs.

Figure 4.4 ▶ Example electricity demand and residual load



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The capacity factor of variable renewables (varRE) per load segment can be calculated based on generation per load segment s of the residual load:

$$Capacity\ factor_s = \frac{Reduction\ Generation\ Needs_{non-var,s}}{Capacity_{varRE}} = \frac{Generation\ varRE_s}{Capacity_{varRE}}$$

For capacity additions, the peak load segment is relevant. The capacity credit is estimated based on the difference between maximal load and maximal residual load:

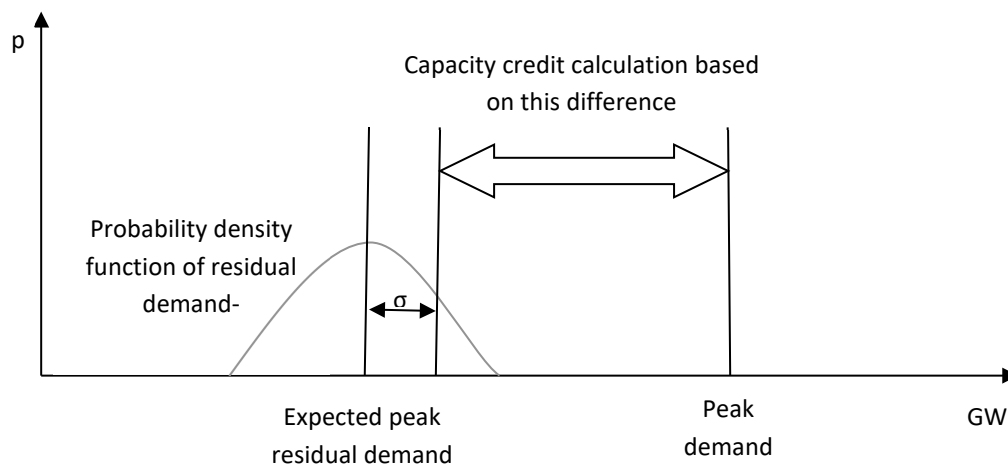
$$Capacity\ credit_{peak} = \frac{Reduction\ Capacity\ Needs_{non-var}}{Capacity_{varRE}} = \frac{\max_t(Load(t)) - \max_t(Residual\ Load(t))}{Capacity_{varRE}}$$

Meteorological data (wind speed and solar irradiation) for several years was used for the capacity credit calculation. In aggregating the results of capacity credit obtained from different years of meteorological data, as a first order approach it was assumed that the annual peak residual demand is normally distributed and the capacity credit was calculated based on the difference between peak demand and the point one standard deviation above the residual peak demand (Figure 4.5).

The meteorological data stem from the following reanalysis datasets:

- World Wind Atlas (Sander + Partner GmbH): Global dataset of hourly wind speeds at 10-metre height, 1979-2009.
- Wind supply time series for the western and eastern United States as derived by (NREL, 2010a) and (NREL, 2011).
- Wind and solar supply time series for Europe-27 as provided by Siemens AG (Heide et al., 2010) for each major Region in Europe. Original meteorological wind speed stems from Reanalysis data (WEPROG, 2010).
- Hourly solar irradiation data from satellite observations for the United States (NREL, 2010b).
- Estimation of solar irradiation based on solar height (Aboumahboub et al., 2010).

Figure 4.5 ▶ Example of electricity demand and residual load



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4.2 Value-adjusted Levelised Cost of Electricity

Major contributors to the LCOE include overnight capital costs; capacity factor that describes the average output over the year relative to the maximum rated capacity (typical values provided); the cost of fuel inputs; plus O&M. Economic lifetime assumptions are 25 years for solar PV, onshore and offshore wind. For all technologies, a standard weighted average cost of capital was assumed (7-8% based on the stage of economic development, in real terms).

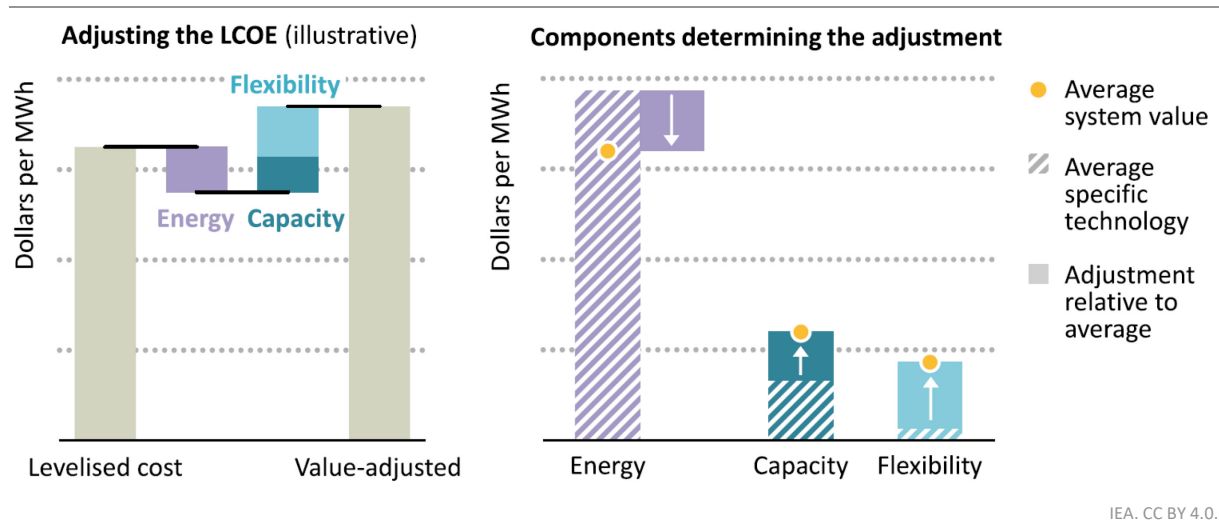
The value-adjusted LCOE (VALCOE) is a metric for competitiveness for power generation technologies, building on the capabilities of the GEC Model hourly power supply model. It is intended to complement the LCOE, which only captures relevant information on costs and does not reflect the differing value propositions of technologies. While LCOE has the advantage of compressing all the direct technology costs into a single metric which is easy to understand, it nevertheless has significant shortcomings: it lacks representation of value or indirect costs to the system, and it is particularly poor for comparing technologies that operate differently (e.g. variable renewables and dispatchable technologies). VALCOE enables comparisons that take account of both cost and value to be made between variable renewables and dispatchable thermal technologies.

The VALCOE builds on the foundation of the average LCOE (or LRMC) by technology, adding three elements of value: energy, capacity and flexibility. For each technology, the estimated value elements are compared against the system average to calculate the adjustment (either up or down) to the LCOE. After adjustments are applied to all technologies, the VALCOE then provides a basis for evaluating competitiveness, with the technology that has the lowest number being the most competitive (Figure 4.6). The VALCOE is applicable in all systems, as energy, capacity and flexibility services are provided and necessary in all systems, even though they may not be remunerated individually. In this way, it takes the perspective of policy makers and planners. It does not necessarily represent the perspective of investors, who would consider only available revenue streams, which may also include subsidies and other support measures, such as special tax provisions, that are not included in the VALCOE.

The impact of the value adjustment varies by technology depending on operating patterns and system-specific conditions. Dispatchable technologies that operate only during peak times have high costs per megawatt-hour (MWh), but also relatively high value per MWh. For baseload technologies, value tends to be close to the system average and therefore they have a small value adjustment. For variable renewables, the value adjustment

depends mainly on the resource and production profile, the alignment with the shape of electricity demand and the share of variable renewables already in the system. Different operational patterns can be accounted for in the VALCOE, improving comparisons across dispatchable technologies.

Figure 4.6 ▶ Moving beyond the Levelised Cost of Electricity to the value-adjusted Levelised Cost of Electricity



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Note: LCOE = Levelised Cost of Electricity.

The VALCOE is composed of LCOE and energy, capacity as well as flexibility value. Its calculation goes as follows:

$$VALCOE_x = LCOE_x + \overbrace{\left[\overbrace{\bar{E} - E_x}^{\text{Energy value}} + \overbrace{\bar{C} - C_x}^{\text{Capacity value}} + \overbrace{\bar{F} - F_x}^{\text{Flexibility value}} \right]}^{\text{Value adjustments}}$$

The adjustment for energy value $[E_x]$ of a technology x (or generation unit) is the difference between the individual unit to the system average unit $[\bar{E}]$. $[E_x]$ is calculated as follows:

$$Energy\ value_x \left(\frac{\$}{MWh} \right) = \frac{\sum_h^{8760} [WholesalePrice_h \left(\frac{\$}{MWh} \right) \times Output_{x,h} (MW)]}{\sum_h^{8760} Output_{x,h} (MW)}$$

Wholesale electricity prices and output volumes for each technology x in each hour h of the year are simulated. Wholesale prices are based on the marginal cost of generation only and do not include any scarcity pricing or other cost adders, such as operating reserves demand curves present in US markets. Hourly models are applied for the United States, European Union, China and India. For other regions, wholesale prices and output volumes are simulated for the four segments of the year presented in Section 4.1.2.

The adjustment for capacity value $[C_x]$ of a generation unit is calculated as follows:

$$Capacity\ value_x \left(\frac{\$}{MWh} \right) = \frac{Capacity\ credit_x \times Basis\ capacity\ value (\$/kW)}{(capacity\ factor_x \times hours\ in\ year / 1000)}$$

The capacity credit reflects the contribution to system adequacy and it is differentiated for dispatchable versus renewable technologies:

- dispatchable power plants = (1-unplanned outage rate by technology)
- renewables = analysis of technology-specific values by region with hourly modelling.

The basis capacity value is determined based on simulation of capacity market, set by the highest “bid” for capacity payment. Positive bids reflect the payment needed to fill the gap between total generation costs (including capital recovery) and available revenue.

The capacity factor is differentiated by technology:

- dispatchable power plants = modelled as simulated operations in previous year
- wind and solar PV = aligned with latest performance data from IRENA and other sources, improving over time due to technology improvements
- hydropower and other renewables = aligned with latest performance data by region and long-term regional averages.

The flexibility value [F_x] of a generation unit is calculated as follows:

$$Flexibility\ value_x \left(\frac{\$}{MWh} \right) = \frac{Flexibility\ value\ multiplier_x \times Base\ flexibility\ value \left(\frac{\$}{kW} \right)}{(capacity\ factor_x \times hours\ in\ year / 1000)}$$

- The Flexibility value multiplier by technology is based on available market data and held constant over time. Targeted changes in the operations of power plants to increase flexibility value are not represented.
- The Base flexibility value is a function of the annual share of variable renewables in generation, informed by available market data in the European Union and United States. The flexibility value is assumed to increase with rising variable renewable energy (VRE) shares, up to a maximum equal to the full fixed capital recovery costs of a peaking plant.

Advantages and limitations of the value-adjusted Levelised Cost of Electricity

VALCOE has several advantages over the LCOE alone:

- It provides a more sophisticated metric of competitiveness, incorporating technology-specific information and system-specific characteristics.
- It reflects information/estimations of value provided to the system by each technology (energy, capacity/adequacy and flexibility).
- It provides a robust metric of competitiveness across technologies with different operational characteristics (e.g. baseload to peaking, or dispatchable to variable).
- It provides a robust metric of competitiveness with rising shares of wind and solar PV.

However, network integration costs are not included, nor are environmental externalities unless explicitly priced in the markets. Fuel diversity concerns, a critical element of electricity security, are also not reflected in the VALCOE.

The VALCOE approach has some parallels elsewhere, in other approaches used for long-term energy analysis, as well as some real-world applications. The VALCOE is most closely related to the System LCOE, which provides a comprehensive theoretical framework for assessing system value beyond the LCOE (Ueckerdt et al., 2013). The VALCOE and System LCOE are similar in scope, and re-arranging terms can align significant portions of the computations. Optimisation models implicitly represent the cost and value of technologies through standard profitability metrics, such as net present value and internal rates of return, but may be limited by the scope of costs included, such as those related to ancillary services. Other long-term energy modelling frameworks have incorporated cost and value metrics in capacity expansion decisions, such as the Levelised Avoided Cost of Electricity built into the National Energy Modelling System used by the US Energy Information Administration. In policy applications, in the 2017 clean energy auction schemes in Mexico, average energy values for prospective projects have been simulated and used to adjust the bid prices, seeking to identify the most cost-effective projects. As clean energy transitions progress around the world, experience with higher shares of wind and

solar PV in large systems will increase and provide opportunities to refine the VALCOE and other metrics of competitiveness.

Financing costs for utility-scale solar PV

The declining costs of solar PV have been impressive, with innovation driving down construction costs by 80% from 2010 to 2019 (IRENA, 2020). Cost reductions have been complemented by improved performance resulting from higher efficiency panels and greater use of tracking equipment. Financing costs, however, have received little attention, despite their importance. The weighted average cost of capital (WACC) can account for until half of the LCOE of utility-scale solar PV projects.

WEO-2020 focused on financing cost through extensive work based on data from financial markets and academic literature, and on the analysis of auction results and power purchase agreements (PPAs), complemented by a large number of confidential interviews with experts and practitioners around the world. The analysis found that in 2019, WACCs for new utility-scale solar PV projects with revenue support stood at 2.4-4.5% in Europe and the United States (in real terms, pre-tax), 3.4-3.6% in China and 5.0-6.6% in India. The analysis of business models draws on the key revenue risk components – price, volume and off-taker risk – and their implications for the cost of capital. It focuses on models where prices paid for solar generation are defined largely by policy mechanisms, which support the vast majority of deployment worldwide. The findings of this analysis on the prevailing average costs of capital in major solar PV markets underpin the projections in the GEC Model. Full merchant projects (without any form of price guarantee external to markets) were considered as a point of comparison and an indicative WACC provided, though to date this model remains somewhat theoretical for solar PV. In the longer term, this type of investment may become more common.

4.3 Electricity transmission and distribution networks

The model calculates electricity transmission and distribution network expansion and replacement along with associated investment per region. Transmission networks transport large volumes of electricity over long distances at high voltage. Most large generators and some large-scale industrial users of electricity are connected directly to transmission networks. Distribution networks transform high-voltage electricity from the transmission network into lower voltages, for use by light-industrial, commercial, and domestic end-users.

Electricity networks in the GEC Model are divided into several categories: represented as five distinct voltage ranges, overhead line or underground cable, and by alternating current (AC) or direct current (DC), creating 20 possible line or cable types. This allows for increased granularity on equipment costs, material needs, and regional differences. This information is then used in the model to understand current and projected composition of networks, as line expansion projections carry the same level of detail on line and cable type. Because of this, costs that are region- and line-specific can be paired with line and cable type to create a model representation of investment needs for that particular grid. In addition, this detailed view of line and cable type is then paired with materials use per km, notably with critical minerals, to form projections of materials demand due to the growing electricity network.

The need for new electricity network line lengths is driven by three factors: to replace existing lines nearing the end of their technical lifetime, to support increasing electricity demand, and to integrate additional renewables in the power sector.

Line replacement due to ageing infrastructure

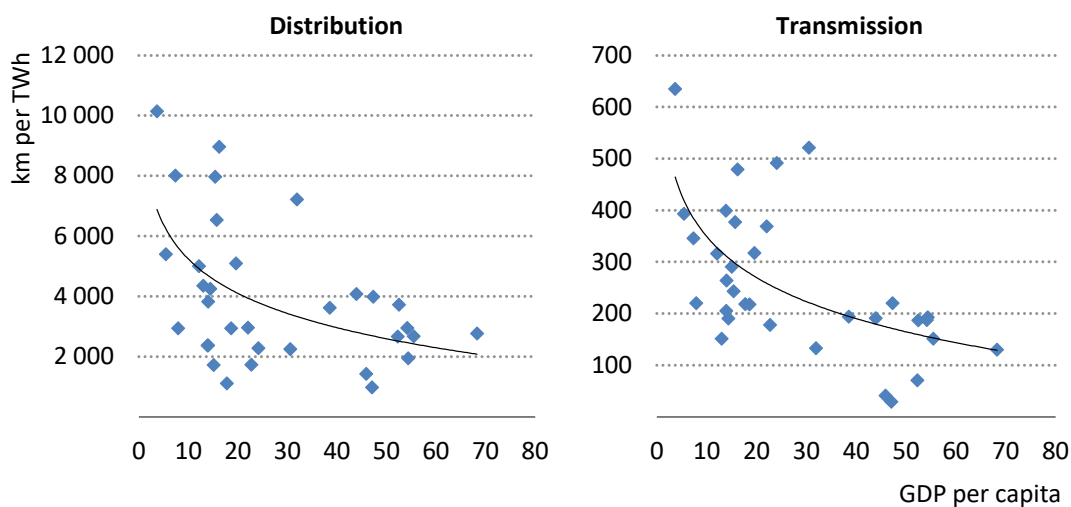
Assuming an average lifetime of 40 years for lines and cables, the model calculates annual replacements accordingly. While this does not increase the overall size of the network, it adds millions of kilometres (km) of

new lines and cables each year that must be accounted for in terms of investments and material demand, as well as for project planning.

Line length expansion due to electricity demand growth

Network expansion increases alongside growth in electricity demand. In order to represent this, a dynamic relationship between network expansion per unit of demand growth was created that relates to GDP per capita. In this, the km of line length per terawatt-hour (TWh) of demand for each region is used in conjunction with the GDP per capita for the given region, in order to produce an equation that represents this global-level relationship. As the network growth rates differ between the distribution and transmission level, this relationship was done for each, yielding two sets of alpha and beta parameters that can be used accordingly.

Figure 4.7 ▶ Electricity network expansion per unit of electricity demand growth by GDP per capita



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Line length expansion due to renewables

A considerable amount of the capacity additions projected over the modelling horizon is from renewables. The location of these technologies is often strongly influenced by the location of the underlying resource (e.g. areas where the wind is strong or insolation is high), which may not be close to existing centres of demand. In addition, some of these technologies, mainly solar PV, are connected at the end-user side of the grid infrastructure. This modular deployment of generation capacity can lead to increased distribution capacity needs.

Because the introduction of large quantities of remote or variable renewables was not a marked feature of the historic development of electricity networks (except for regions where remote hydroelectricity represents a large proportion of the generation mix), the addition of more renewables is likely to increase the average length of network additions.

Line expansion is being driven by two factors: the transmission lines that connect solar and wind farms to the grid, and reinforcement requirements within the grid. A factor for the average connecting line length was derived from the average line length connecting past utility-scale solar PV, wind onshore and wind offshore projects. The added capacity from these renewable energy technologies is multiplied by the historical relationship to obtain related line extensions.

The grid reinforcements are based on a study conducted in countries with high renewable energy development. Up to a threshold of the share of renewable generation, there is no need for grid improvements. An increase in

the share beyond this threshold leads to additional lengths to reinforce the grid, based on the literature and projected shares of renewables by region and scenario.

The estimation of distribution grid extensions for renewables contains more uncertainties than the transmission grid, as less data or studies are available on the technically complex distribution network and own use of distributed generation can in turn lead to a reduced need for distribution grid infrastructure. Therefore, we assume that additional network investment is required only if the electricity generated from distributed generation, such as solar PV in buildings, exceeds local demand and is fed back to the system.

Transformer capacity expansion due to electricity demand and supply growth

Transformer capacity is based on historical data associated with the power generation capacity in each GEC region. For the calculation of transformer capacity growth, new power capacity is taken into consideration whereas all small-scale solar PV is deducted as it is assumed that most output will be used locally. Another portion of solar PV will be connected to the distribution network and is accounted for, and part of additional battery storage capacity is deducted as it will reduce the flow of power through the grid and therefore the need for transformer capacity.

Transformer replacement due to ageing

Assuming an average lifetime of 40 years for transformers, annual replacements are calculated accordingly. While this does not increase the overall capacity in the network, it adds transformer capacity each year that must be accounted for in terms of investment and material demand.

Electricity network investment

Investments for electricity networks are composed of those related to the three main drivers of line length expansion: increasing demand, replacements and increase in renewables. In addition, they also include investments due to components other than line length such as grid forming requirements and transmission level reinforcement. For the line length components of the investment, which comprise the majority of overall network investments, the model calculates this as the network expansion in km due to a given driver multiplied by the unit cost for each line and cable type.

Grid forming requirements are also incorporated into the electricity network representation, related to the extent of the shift to variable renewables in the projections. Variable renewables lack mechanical inertia as they connect to the network via a converter. Inertia comes from the large rotating masses in the generators in power plants and is necessary to keep the network stabilised, especially in case of fault events. With the rising share of variable renewables, the network needs grid forming stabilising technology from the Flexible AC Transmission Systems (FACTS) family. The calculation for this investment is based on deployment needs realised in countries with a high share of renewables. The investment is driven by the expansion of renewables generation above a minimum level and increases based on assessed needs in each region. Below the minimum level, the grid remains stable without additional measures.

Each of the electricity network equipment unit costs have been created using an average of project and national-level costs, collected from publications that detail costs per km based on corresponding line and cable type. They represent costs from several regions globally, allowing for a balanced view of region-specific costs. These costs are then tailored further per region, creating a series of 20 different costs per km for each region. Similarly, replacement costs are also line- and region-specific. For all types and regions, replacement costs are lower than that of new lines, as permitting, land, and many of the capital costs do not need to be redone. However, region-specific discounters are used to differentiate between material use per region as well as labour costs per region, two factors that can greatly influence costs per km. Bringing together all of these costs and drivers for network

expansion, the model calculates overall network investment with the following equation for each of the 20 line and cable types:

Annual transmission investment by region =

$$\sum_{V,P,C} [\text{cost new lines}_{V,P,C} * \left(\begin{aligned} &\Delta \text{ electricity demand} * (\alpha * \ln(\text{GDP per capita}) + \beta) * \text{grid composition}_{V,P,C} \\ &+ \sum_R (\text{renewables additions}_R * \gamma_{V,P,C}) \\ &+ \Delta \text{ share of variable renewables} * \psi * \text{total transmission length}_{V,P,C} \end{aligned} \right) \\ + \text{cost replacement}_{V,P,C} * \text{lines replacement}_{V,P,C}] \\ + \text{cost STATCOM} * \phi * \Delta \text{ share of variable renewables installed} * \text{total power capacity}$$

Annual distribution investment by region =

$$\sum_{V,P,C} [\text{cost new lines}_{V,P,C} * \left(\begin{aligned} &\Delta \text{ electricity demand} * (\alpha * \ln(\text{GDP per capita}) + \beta) * \text{grid composition}_{V,P,C} \\ &+ \sum_R (\text{renewables additions}_R * \gamma_{V,P,C}) \end{aligned} \right) \\ + \text{cost replacement}_{V,P,C} * \text{lines replacement}_{V,P,C}]$$

Where:

- V is voltage level band
- P is position (overhead, underground)
- C is current (AC or DC)
- R is the renewable energy technology
- $\text{grid composition}_{V,P,C}$ is the historical shares of the grid by voltage, position, and current
- α, β are dimensionless variables in the equation relating demand growth to GDP per capita, derived from historical data by region
- γ is the additional line lengths required to connect new renewables capacity additions, measured in km per GW, by voltage, position and current
- ψ is the dimensionless factor of additional transmission network requirements due to high shares of variable renewables, where it exceeds a minimum threshold
- $\Delta \text{ electricity demand}$ is the annual increase in electricity demand in the region
- $\Delta \text{ share of variable renewables}$ is the annual increase in share of variable renewables in total installed capacity
- $\text{lines replacement}_{V,P,C}$ are the lines to be replaced, in km, defined as those reaching 40 years of use
- cost STATCOM is the cost of STATCOM devices (static synchronous compensators)
- ϕ is the dimensionless factor of additional grid forming requirements due to high shares of variable renewables, given that the share of renewables exceeds a minimum threshold. The current annual expenditures of both the Distribution System Operator (DSO) and Transmission System Operator (TSO) undergo examination across various regions, and these figures are linked to the calculated investment. It is important to note that the investment in grid infrastructure does not adhere to a spending model that spreads the investment over time, in contrast to the approach used for calculating investments in power generation.

4.4 Hourly models

To quantify the scale of the challenge arising from the integration of high shares of VRE and to assess which measures could be used to minimise curtailment, an hourly model was developed for *WEO-2016*, to provide further insights into the operations of power systems. The model builds upon the annual projections generated in the GEC Model and makes it possible to explore emerging issues in power systems, such as those that arise as the share of VRE continues to rise. The model then feeds the main GEC Model with information about additional constraints on the operations of different power plants. The model is a classical hourly dispatch model, representing all hours in the year, setting the objective of meeting electricity demand in each hour of the day for each day of the year at the lowest possible cost, while respecting operational constraints.¹ All 106 power plant types recorded in the GEC Model and their installed capacities are represented in the hourly model, including existing and new fossil-fuelled power plants, nuclear plants and 16 different renewable energy technologies. The fleet of power plants that is available in each year is determined in the GEC Model and differs by scenario, depending on the prevalent policy framework. These plants are then made available to the hourly model and are dispatched (or chosen to operate) on the basis of the short-run marginal operating costs of each plant (which are mainly determined by fuel costs as projected in the GEC Model) to the extent required to meet demand. The dispatch operates under constraints: there are minimum generation levels to ensure the flexibility and stability of the power system and to meet other needs (such as CHP); the variability of renewable resources (such as wind and solar) determines the availability of variable renewables and, hence, the maximum output at any point in time; and ramping constraints apply, derived from the level of output in the preceding hour and the characteristics of different types of power plants. The hourly dispatch model does not represent the transmission and distribution system, nor grid bottlenecks, cross-border flows or the flow of power through the grid. It therefore simulates systems that are able to achieve full integration across balancing areas in each GEC Model region (e.g. United States, European Union, China and India).

Key inputs to the model include detailed aggregate hourly production profiles for wind power and solar PV for each region, which were generated by combining simulated production profiles for hundreds of individual wind parks and solar PV installations, distributed across the relevant region.² The individual sites were chosen to represent a broad distribution within a region, allowing the model to represent the smoothing effect achieved by expanding balancing areas. On the demand side, the model uses a detailed analysis, with hourly demand profiles for each specific end-use (such as for lighting or water heating in the residential sector), coupled with the annual evolution of electricity demand by specific end-use over the model horizon from the main GEC Model (see Section 3.4).

The hourly model accounts for grid, flexible generation and system-friendly development of VRE, in three steps: first, it assesses the amount of curtailment of variable renewables that would occur without demand-side response and storage. Second, it deploys demand-side response measures, based on the available potential in each hour for each electricity end-use. And third, it uses existing and new storage facilities to determine the economic operations of storage based on the price differential across hours and charge/discharge periods. It thereby enables the integration needs arising from growing shares of renewables to be assessed.

Among the other important model outputs is the resulting hourly market price, which can drop to zero in the hours when generation from zero marginal cost generators (such as variable renewables) is sufficient to meet demand. By multiplying the market price by generation output in each hour, the model calculates the revenues received for the output in each hour by each type of plant, creating a basis for calculating the value of VRE. The model also provides hourly operation information for each plant type, including fuel costs and associated GHG and pollutant emissions.

¹ The model works on an hourly granularity, and therefore any intra-hour values of different devices (e.g. of storage technologies) are not captured.

² Wind and solar PV data are from Renewables.ninja (<https://www.renewables.ninja/>) and Ueckerdt et. al. (2016).

Modelling seasonal variability and long-term storage

To assess the impact of weather-induced variability on power system operations and long-term flexibility needs in systems characterised by rising shares of variable renewables and temperature-sensitive end uses such as electric heating and cooling, a new hourly dispatch model was developed for the *WEO-2023*. Building on the annual projections of the GEC Model, it is applied to quantify power system flexibility needs on timescales ranging from hours over days and weeks to seasons and identify how these needs can be met in a cost-optimal manner. It represents all hours in a year, setting the objective of meeting electricity demand in each hour of the year at the lowest possible cost, while respecting operational constraints. The model was built in Python using the *PyPSA* open-source Python environment for energy system modelling³ and is solved using linear optimisation. The optimisation ensures that power plants, energy storage technologies, demand response and electrolyzers are operated in a way that minimises the total system cost (thus maximising their utility to the system) on an hourly granularity for a given year.

Production profiles for wind, solar PV and run-of-river hydro, as well as inflow profiles for reservoir hydro were generated using the *Atlite* open-source Python library, which provides functions that convert weather data such as wind speeds, solar irradiance, temperature and runoff into hourly wind power, solar power, run-of-river hydro power, hydro reservoir inflow and heating demand profiles (Hoffman et al., 2021). To assess the potential variability of weather-dependent renewables and temperature-dependent demand across years and capture extreme events, weather data for 30 historical weather years⁴ (1987-2016) was obtained from the ERA5 reanalysis dataset of European Centre for Medium-Range Weather Forecasts, which covers the entire globe at 30-km resolution.⁵

To model the long-term impact of weather-related variability in systems dominated by renewables, the model includes a detailed representation of reservoir and pumped storage hydro, as well as temperature-sensitive demand and demand response (see Section 3.4), hydrogen electrolyzers and hydrogen storage. Hydro reservoir and pumped storage dispatch is constrained by water levels in the reservoir, with natural inflows derived based on runoffs and hydrological basins for each hydropower plant. To model the possible interaction between the electricity and hydrogen systems, the model optimises the operation of grid-connected electrolyzers, hydrogen storage and thermal power plants using hydrogen, while considering hydrogen production from off-grid electrolyzers connected to dedicated renewables as well as demand profiles for other uses of hydrogen. To reflect the impact of constraints in the transmission system, the modelled GEC regions (Europe, India and Indonesia) are disaggregated into several nodes that can exchange electricity between each other, with the exchanges limited by the overall capacity of the transmission system between each of the nodes.

Assessing flexibility needs

Flexibility can be defined as the ability of a power system to reliably and cost-effectively manage the variability and uncertainty of supply and demand across all relevant timescales. Flexibility needs can be seen as the balancing effort required to smoothen the residual load over a given timescale (which could then be satisfied with baseload capacity). To account for specific flexibility needs of the system depending on the timescale, we distinguish between short-term and seasonal flexibility needs in the *WEO-2024*. Short-term flexibility needs are calculated as the average hourly ramp (difference in the residual load between a given hour and the previous hour) of the residual load over the top-100 hours with the highest upward ramps, divided by the average hourly electricity demand for the year (electricity demand in this case does not include battery charging, pumped storage pumping or net exports). Seasonal flexibility needs are assessed by computing the difference between the weekly and annual average of the residual load, divided by the annual electricity demand.

³ <https://pypsa.org/>

⁴ A weather year is a set of weather parameters such as temperature, solar radiation, wind speed and precipitation compiled from historical records to create curves of hourly loads and renewables output.

⁵ <https://www.ecmwf.int/en/forecasts/dataset/ecmwf-reanalysis-v5>

Short-term flexibility needs are computed as follows:

$$Ramp(t) = ResidualLoad(t) - ResidualLoad(t - 1h)$$

$$FlexibilityNeeds_{year,short-term} = \frac{\sum_{t \in \{t_1, t_2, \dots, t_{100}\} \text{ with } Ramp(t_i) \geq Ramp(t_{i+1})} Ramp(t)}{\frac{100}{AnnualElectricityDemand_{year}}} \cdot 8760$$

Seasonal flexibility needs are computed as follows:

$$FlexibilityNeeds_{year,seasonal} = \frac{\sum_{t \in year} |ResidualLoadWeeklyAvg(t) - ResidualLoadAnnualAvg(t)|}{AnnualElectricityDemand_{year}}$$

4.5 Mini- and off-grid power systems

Since the *Africa Energy Outlook* in 2014, the representation of mini- and off-grid systems, related to those gaining access to electricity, has been improved and better integrated into the GEC Model. In line with the approach for on-grid power systems, to meet additional electricity demand, the model chooses between available technologies for mini- and off-grid systems based on their regional long-run marginal costs, using detailed geospatial modelling to take into account several determining factors. For the *Africa Energy Outlook 2019*, the IEA refined its analysis using up-to-date technology costs, demand projections, and the latest version of the Open Source Spatial Electrification Tool (OnSSET)⁶ developed by the KTH Royal Institute of Technology, to cover in detail 44 countries in sub-Saharan Africa. The technologies are restricted by the available resources in each region, including renewable energy resources such as river systems, biomass feedstocks (e.g. forests and agricultural residues), wind and the strength of solar insolation. Back-up power generation for those with access to the grid, typically gasoline or diesel fuelled, is also represented in the model, with its projected use tied to the quality of the on-grid power supply.

4.6 Renewables and combined heat and power modules

The projections for renewable electricity generation and CHP are derived in separate sub-modules.

4.6.1 Combined heat and power and distributed generation

The CHP option is considered for fossil fuel and bioenergy-based power plants. The CHP sub-module uses the potential for heat production in industry and buildings together with heat demand projections, which are estimated econometrically in the demand modules.

4.6.2 Renewable energy

The projections of renewable electricity generation are derived in the renewables sub-module. The deployment of renewables is modelled based on policy targets, technology competitiveness and resource potential, specified for each technology (bioenergy, hydropower, solar PV, CSP, geothermal electricity, wind, and marine) in each of the GEC Model regions.⁷ Policy targets are often for specific technologies, for example, over 130 countries have support policies in place to expand the use of solar PV and wind as of 2020. Other policies may specify the total contribution of renewable energy, the share of renewables in total electricity generation, or the low-emissions

⁶ For more details on the Open Source Spatial Electrification Tool, see www.onsset.org. For the latest OnSSET methodology update, refer to Korkovelos, A. et al. (2019).

⁷ A number of sub-types of these technologies are modelled individually, as follows. Biomass: small CHP, medium CHP, electricity only power plants, biogas-fired, waste-to-energy fired and co-fired plants. Hydro: large (≥ 10 MW) and small (< 10 MW). Wind: onshore and offshore. Solar PV: large-scale and buildings. Geothermal: electricity only and CHP. Marine: tidal and wave technologies.

share of generation including renewables. In cases where policies specify a broad target that includes renewables, technology competitiveness and resource potentials drive the relative contributions. Technology competitiveness is based on the VALCOE (see Section 4.2) and applies equally to comparisons amongst renewable energy technologies and a broader set of technologies. Resource potential is considered on a regional basis for each renewable energy technology (see Box 4.1). Beyond the reach of policy targets, technology competitiveness and resource potentials are the critical considerations for renewables deployment. Market constraints, including administrative ones, and technical barriers such as grid constraints, where applicable, are considered, and are most important in the near term as technologies mature.

Electricity generation from newly built renewables is calculated based on an assessment of historical operations and evolving technology designs. For example, wind turbine designs have improved over the past decade, achieving higher performance under a variety of wind conditions. Assumed capacity factors for new renewable energy projects are technology- and region-specific. Total electricity generation from a renewable technology is the sum of all projects in operation within a given year.

Overnight investment needs for renewables are calculated based on the deployment of renewables and evolving technology costs. Our modelling, in all scenarios, incorporates a process of learning-by-doing for projected capital costs for renewables (and other technologies not yet mature). Learning rates are assumed by decade for specific technologies. The overall evolution of the technology costs are commonly expressed through the LCOE. While technology learning is integral to the approach, the GEC Model does not try to anticipate technology breakthroughs.

Box 4.1 ▶ Long-term potential of renewables

The starting point for deriving future deployment of renewables is the assessment of long-term realisable potentials for each type of renewable and for each region. The assessment is based on a review of the existing literature and on the refinement of available data. It includes the following steps:

- The *theoretical* potentials for each region are derived. General physical parameters are taken into account to determine the theoretical upper limit of what can be produced from a particular energy, based on current scientific knowledge.
- The *technical* potential can be derived from an observation of boundary conditions such as the efficiency of conversion technologies and the available land area to install wind turbines. For most resources, technical potential is a changing factor. With increased R&D, conversion technologies might be improved and the technical potential increased.

Long-term *realisable* potential is the fraction of the overall technical potential that can be actually realised in the long term. To estimate it, overall constraints such as technical feasibility, social acceptance, planning requirements and industrial growth are taken into consideration.

Wind offshore technical potential

In collaboration with Imperial College London, a detailed geospatial analysis was undertaken for *WEO-2019* to assess the technical potential for offshore wind worldwide. The study was among the first to use the “ERA-5” reanalysis, which provides four decades of historic global weather data. “Renewables.ninja” extrapolates wind speeds to the desired hub height and converts them to output using manufacturers’ power curves for turbine models. Results can be found on the IEA website.

Data

The availability of high-resolution satellite data and computing gains has significantly improved the granularity and accuracy of wind resource assessments in recent years. Emerging wind turbine designs are also cause to

update potential assessments, as they increase performance in well-established areas and make lower quality resources more suitable for energy production.

Exclusions

Commercially available offshore wind turbines are currently designed for wind speeds of more than 6 m/s. Some companies are also looking into turbine designs for lower wind speeds.

Following the International Union for Conservation of Nature's (IUCN) classification of maritime protection areas, those categorised as Ia, Ib, II and III were excluded from the study (IUCN, 2008). However, at each project level other environmental considerations must also be taken into account and a full environmental impact assessment conducted as mandated by public authorities. Buffer zones were also excluded for existing submarine cables (within 1 km), major shipping lanes (20 km), earthquake fault lines (20 km) and competing uses such as existing offshore oil and gas installations and fisheries.

Turbine designs

In order to assess the global technical potential, best-in-class turbines were chosen with specific power of 250, 300 and 350 watts per square metre (W/m^2) that corresponds to low-medium, medium and high wind speeds. The power curves of these turbines were used in conjunction with the global capacity factors of each 5 km by 5 km cell selected for the analysis to derive the technical potential of offshore wind in terms of capacity and generation. New power curves were synthesised for next-generation turbines with rated capacity of up to 20 MW, for which data are not yet available (Saint-Drenan, 2020).

Further to this, the analysis takes into account further considerations such as offshore wind farm designs, distance from shore and water depth, offshore wind cost developments and the technical potential.

4.7 Hydrogen and ammonia in electricity generation

Low-emissions hydrogen and ammonia are fuels that can provide a low-emissions alternative to natural gas- and coal-fired electricity generation – either through co-firing or full conversion of facilities. In the GEC Model, blending levels of hydrogen in gas-fired plants and ammonia in coal-fired plants are specified in line with policy and emissions targets. As part of the scenarios, the shares of hydrogen and/or ammonia blending increase over time, representing both advances in the capability to retrofit existing facilities to co-fire higher shares of hydrogen and/or ammonia, and the uptake of new designs that are designed to blend higher shares of hydrogen or ammonia, or plants that are purposely designed to run entirely on hydrogen or ammonia.

Increased levels of hydrogen and ammonia blending in the GEC Model incur additional capital expenditure due to the need for more extensive retrofitting of existing natural gas- and coal-fired power plants.

Electricity sector demand for hydrogen and ammonia is used by the hydrogen supply module to inform the overall demand for hydrogen production.

4.8 Battery storage

Battery storage in the GEC Model provides an important source of power system flexibility, particularly when flexibility needs increase due to evolving electricity demand patterns and rising shares of variable renewables. The model incorporates both utility-scale and behind-the-meter battery storage. Utility-scale battery storage systems are directly connected to the grid. Behind-the-meter battery storage refers to applications at the distribution level, installed at residential, commercial and industrial end-user locations. They are connected to buildings and rooftop solar PV systems, behind the electricity meter and buildings' own connection to the power grid.

In the hourly model, charging and discharging patterns for utility-scale batteries are optimised based on price arbitrage opportunities (i.e. charging when prices are low and discharging when prices are high). Utility-scale battery storage volumes range from one to eight hours in duration (referring to the number of hours a full battery takes to discharge fully at maximum output). Batteries operate only when the difference between the price received for discharging and price paid for charging within a 24-hour period is greater than a certain threshold, which is set based on factors such as upfront capital costs, the expected number of cycles over the battery's lifetime and round-trip efficiency. Like other electricity sector technologies, utility-scale battery investment decisions are based on the VALCOE, with batteries assumed to have different levels of capacity credit depending on their duration – contributing to system adequacy and flexibility. Utility-scale battery storage can either be stand-alone or paired directly with power plants, such as wind and solar PV.

Investments in behind-the-meter batteries are largely driven by the savings potential they provide to electricity consumers. Consumers tend to realise the greatest benefit when combining behind-the-meter battery with rooftop solar PV and in regions with dynamic time-of-use pricing. Consumers will be further incentivised to invest in solar PV and behind-the-meter batteries, and to make the fullest use of them, if grid feed-in is not prohibited or restricted, and if selling back excess solar PV generation is remunerated at full retail prices. Strong incentives can also reduce overall peak demand on the grid. In reducing grid reliance, behind-the-meter batteries can also offer the potential for consumers to downsize the grid connection itself, minimising another monthly charge.

In the model, the deployment of behind-the-meter batteries is linked to the deployment rate of rooftop solar PV based on average country or region-level attachment rates (the ratio of rooftop solar PV to behind-the-meter battery storage capacity). These attachment rates are estimated and projected forward considering country and region-specific regulatory environments and tariff structures, the development of retail electricity prices, subsidies for behind-the-meter storage and the expected cost of behind-the-meter battery storage systems.

Battery storage capital costs are projected to decline over time. The degree of technology cost reductions is calculated based on learning rates from existing literature, applied to the battery pack and to auxiliary components such as inverters, as well as other overhead costs.⁸ For battery packs, projected costs are driven not only by the deployment of batteries in the power sector, but the demand for batteries across all sectors, with by far the largest volumes used in electric vehicles. For the other components of battery storage systems, the decline in cost is estimated based on the cumulative capacity additions of battery energy storage systems themselves.

⁸ Based on Schmidt et al. (2017) and Tsiropoulos et al. (2018).

Other energy transformation

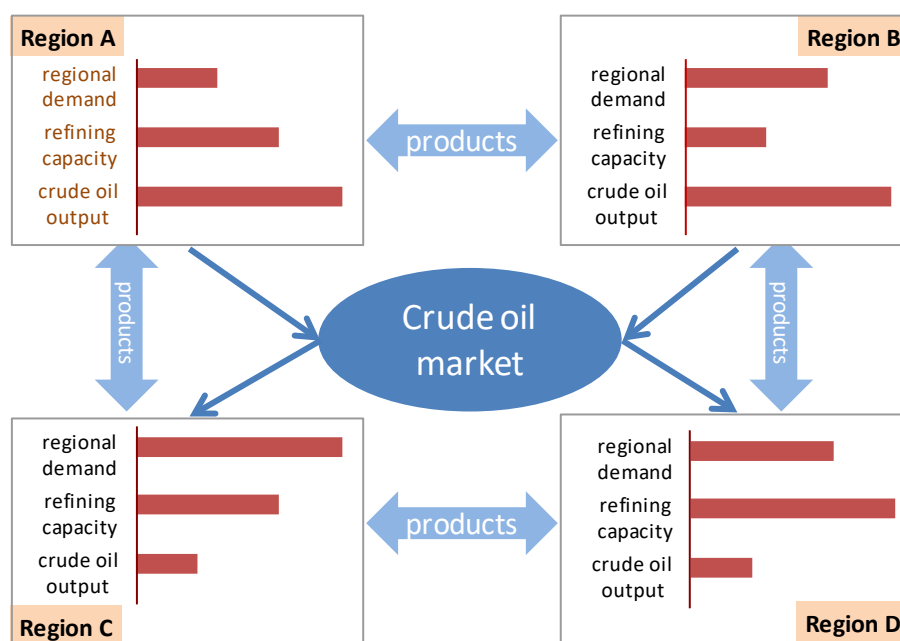
5.1 Oil refining and trade

The refinery and trade module links oil supply and demand. It is a simulation model, with capacity development and utilisation modelled for 134 individual countries, with the remaining countries grouped into 11 regions. This module has several auxiliaries that stretch into supply and demand domains to better link both:

- Natural gas liquids module to determine the supply of light oil products as well as condensate.
- Extra-heavy oil and bitumen module to model synthetic crude oil output and diluent requirements for bitumen.
- Split of oil demand into different product categories for all sectors except road transport and aviation. The latter are provided by GEC Model's transport demand model.

Projections for refining sector activity are based primarily on refining capacity and utilisation rates. Refining capacity consists of crude distillation units and condensate splitters. Refining capacity is based on 2022 data from the IEA. Capacity expansion projects that are currently announced are assessed individually to identify only the projects that are likely to go ahead. Some of these are delayed from their announced start-up dates to allow for a more realistic timeline. The model also takes into account refinery closures that have been announced. Beyond 2028, new capacity expansion is projected based on crude availability and product demand prospects for each of the regions specified below. Capacity at risk is defined as the difference between refinery capacity and refinery runs, with the latter including a 14% allowance for downtime. Projected shutdowns beyond those publicly announced are also counted as capacity at risk.

Figure 5.1 ▶ Schematic of refining and international trade module



IEA. CC BY 4.0.

Utilisation rates are determined by domestic demand, product yields and refinery configuration (e.g. complexity). Among oil-importing regions, priority call on international supply of crude oil is given to those where demand is growing: robust domestic demand is effectively a proxy for refinery margins that are not explicitly calculated or used by the model.