Global Energy and Climate Model

Documentation - 2023

International Energy Agency

INTERNATIONAL ENERGY AGENCY

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Table of Contents

List of figures

List of tables

List of boxes

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 for the first time 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 CO_2 emissions by 2050; this analysis has been updated in 2023.

Over the past two 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 29 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 (http://www.iea.org/statistics). 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 CO_2 emissions from fuel combustion, industrial processes and flaring; methane (CH_4) emissions from fossil fuel operations; CH_4 and nitrous oxide (N_2O) 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 greenhouse gas 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 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. The Announced Pledges Scenario (APS) and the Stated Policies Scenario (STEPS) 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.

Table 1.1 ▹ Definitions and objectives of the *GEC Model 2023* scenarios

	Net Zero Emissions by 2050 Scenario (NZE Scenario)	Announced Pledges Scenario (APS)	Stated Policies Scenario (STEPS)
Definitions	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 fully updated in 2023.	A scenario which assumes that all climate commitments made by governments and industries around the world by the end of August 2023, 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 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 2023, as well as those that are under development. The scenario also takes into account currently planned manufacturing capacities for clean energy technologies.
Objectives	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.	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 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.

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 are available in chapter 2.

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 CO_2 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 CO_2 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 2023 Net Zero Emissions by 2050 Scenario:

- Describes a pathway for the global energy sector to reach net zero emissions of CO_2 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 CO_2 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 CO_2 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 CO_2 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 CO_2 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 (Sustainable Development Goal [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 CO_2 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).

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 2023, 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 CO_2 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.

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 2023, 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.

For the first time in 2023, 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.

1.2 Selected developments in 2023

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

Cross-cutting

- The number of regions included for the 2023 modelling increased from 26 to 29, with the addition of country-specific regions for Chile, Colombia, Costa Rica and Argentina for this cycle's *Latin America Energy Outlook*.
- The NZE Scenario underwent a significant update in 2023, retaining the same design principles while taking into account key changes that have occurred since 2021 in energy policies, technologies, markets and supply chains.

Final energy consumption

Behavioural analysis

- A comprehensive assessment of behavioural changes featuring in announced climate pledges (NDCs and long-term strategies) has been carried out, to allow policies related to behavioural changes to be incorporated into the APS.

Buildings

- Activity drivers including built floor area, appliance ownership by appliance type and air conditioner ownership have been updated with more recent data by country.
- Inputs including building demolition rates and income elasticities have been aligned to the latest literature. Projections of heating and cooling degree days have also been updated following the release of the IPCC Sixth Assessment Report.
- The services sub-sector model has been enhanced, allowing for higher technology granularity in space heating, water heating and space cooling.
- The heat pumps sales and stock module has been enhanced, allowing for higher technology disaggregation to better represent current market trends.

Industry

- For aluminium, the technology granularity has increased, for example by incorporating different processes within alumina refineries.
- For the steel sub-sector model, iron and steel production have been separated more clearly, incorporating the trade of iron and combinations of different production routes.
- The stock modelling functionality has been more closely integrated within the core technology model, allowing for better tracking of scrap metal and plastic waste resources and improved representation of secondary production dynamics.

Transport

- For the road module, cost curves of low-emissions trucks were updated based on recent publications. The road freight module was enhanced, improving the freight activity projections for all truck sizes.
- The connection between the aviation module and the latest version of the Aviation Integrated Model was refined. Hydrogen aircraft energy intensity and occupancy factor analysis was also updated.
- Methanol was incorporated into the shipping module. Policy research was conducted to update the fuel and technology projections.
- A comprehensive update of the rail module was carried out to improve rail activity and energy demand projections and provide resolution by country, including a new framework for historical data accommodating five rail types and three fuels; a new methodology to derive historical activity, energy intensity, mileage and other key metrics; and a new projection methodology for high-speed rail activity.

Hourly electricity demand

- A new hourly load curve model has been developed. Statistical analysis of historical demand allows for the simulation of a region's electricity load curve with a very high level of confidence. Thermosensitivity reflects the impact of variations in weather and enables the simulation of electricity demand across many weather years.

Electricity generation

- A new hourly dispatch model was developed to assess the impact of weather-induced variability on power system operations and long-term flexibility needs.
- Demand by end-use and production profiles for wind, solar PV and run-of-river hydro, as well as inflow profiles for reservoir hydro were generated for 30 weather years[1] in order to assess the variability of system operations and flexibility needs. The model includes a detailed representation of reservoir and pumped storage hydro, as well as temperature-sensitive demand and demand response, hydrogen electrolysers and hydrogen storage.

Energy supply

- New emissions intensities data of upstream oil and gas operations were integrated into the oil and gas model.
- A detailed geospatial analysis of the electrification potential of upstream oil and gas operations was conducted.
- Revised methods to estimate net income and investment from oil and gas operations were implemented.

Other transformation

Hydrogen module

- Global methanol trading has been incorporated into the hydrogen module (TIMES [The Integrated MARKAL-EFOM System] model).
- A new hourly analysis has been developed using the ETHOS (Energy Transformation PatHway Optimization Suite) model suite of the Institute of Energy and Climate Research-3 at Research Centre Jülich to derive the regional production cost curves for hydrogen production from renewable electricity.

Biofuel production module

- Alcohol-to-jet biojet kerosene production route has been added to the liquid biofuels model. Biomethanol production (with and without carbon capture, utilisation and storage [CCUS]) was also added to the liquid biofuels model.
- Biomethanol trade has been added to the model.

Critical minerals

- The GEC model now makes use of the data available in the new interactive Critical Minerals Data Explorer, providing global demand projections for 37 critical minerals across the three main IEA scenarios and 12 technology-specific cases.
- Updates were made to integrate new battery chemistry developments observed since 2022. An alternative case now explores impacts of further high lithium iron phosphate and sodium-ion shares in batteries.

Emissions

- Mine-level data on the type of coal, mine depth and methane gas content were integrated to improve estimates of methane emissions of coal supply.
- Satellite-data, measurement studies, governance indicators and related data used to estimate methane emissions from fossil fuel supply have been updated.

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[1] 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.

Employment

- The scope of the model has been expanded to include employment in nuclear fuel supply, and granularity has been introduced on employment in critical minerals by mineral.

Government spending on clean energy and energy affordability

- The granularity of the government energy spending data has been enhanced, notably with regards to the timeline for disbursement of government funding earmarked both for clean energy investment support and energy affordability for consumers.

1.3 GEC Model overview

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 CO_2, methane (CH_4) and nitrous oxide (N_2O) 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.

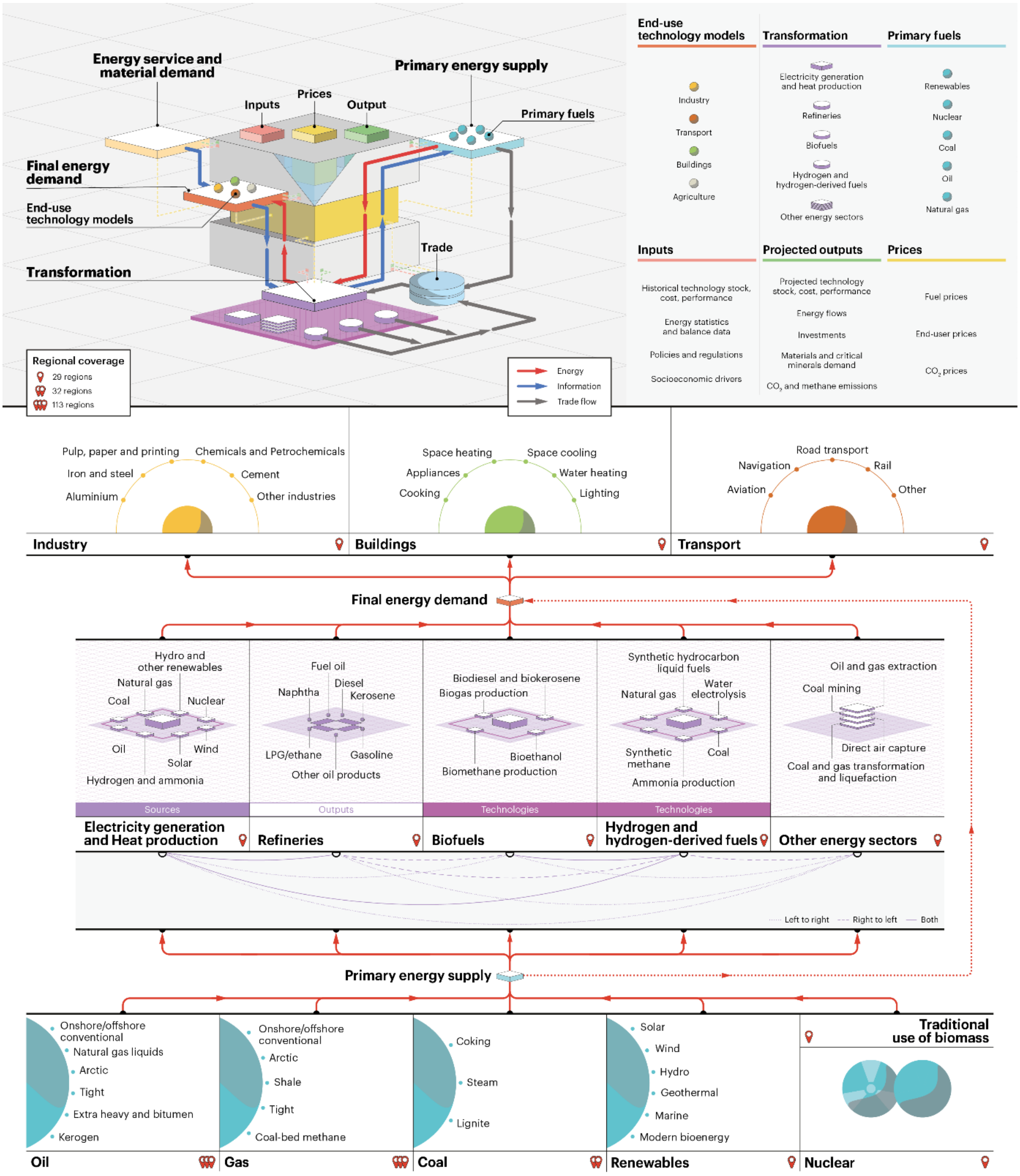
The main exogenous drivers of the scenarios are economic growth, demographic change, and technological developments. Energy service demand drivers, such as steel demand in industry or the number of appliances owned by each household, are estimated econometrically based on historical data and on the socio-economic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

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 CO_2. 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.

Figure 1.1 ▷ Global Energy and Climate Model Overview



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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 CO_2 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 CO_2 emissions of each region are then calculated using derived CO_2 factors, taking into account reductions from CO_2 removal technologies.

The GEC Model is implemented in the simulation software Vensim (https://vensim.com/), but makes use of a wider range of software tools, including TIMES (https://iea-etsap.org/index.php/etsap-tools/model-generators/times).

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 2021, 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 2022 and 2023 estimates for energy production and demand. Estimates for the year 2022 are based on the IEA's *CO_2 Emissions in 2022* 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 2022, based on the IEA *World Energy Investment 2023* report. Data on deployment and techno-economic performance of technologies used in different sector models include 2022 and estimates for 2023, such as data in *Tracking Clean Energy Progress 2023*, the *Global Hydrogen Review 2023*, and the *Global Electric Vehicle Outlook 2023*.

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 (https://www.iea.org/data-and-statistics/data-product/global-energy-and-climate-model-2023-key-input-data).

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 29 regions of the globe, of which 16 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.

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**: CO_2 emissions from fuel combustion are derived from the projections of energy consumption. CO_2 process emissions are based on the production of industrial materials and CH_4 and N_2O 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 CO_2 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 and opportunities to provide 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.

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 gases 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)		
	2000-22	2022-30	2022-50	2022	2030	2050	2022	2030	2050
North America	0.9%	0.6%	0.4%	505	528	565	83%	84%	89%
United States	0.7%	0.5%	0.4%	336	350	372	83%	85%	89%
C & S America	1.0%	0.7%	0.5%	529	559	601	82%	83%	88%
Brazil	0.9%	0.5%	0.2%	215	224	231	88%	89%	92%
Europe	0.3%	0.0%	-0.1%	695	696	682	76%	78%	84%
European Union	0.2%	-0.1%	-0.2%	449	446	426	75%	77%	83%
Africa	2.6%	2.3%	2.0%	1 425	1 708	2 482	44%	48%	59%
Middle East	2.2%	1.4%	1.1%	265	297	364	73%	75%	81%
Eurasia	0.4%	0.3%	0.2%	238	243	253	65%	67%	73%
Russia	-0.1%	-0.3%	-0.3%	143	140	132	75%	77%	83%
Asia Pacific	1.0%	0.6%	0.3%	4 295	4 489	4 734	50%	55%	64%
China	0.5%	-0.1%	-0.3%	1 420	1 410	1 307	64%	71%	80%
India	1.3%	0.8%	0.6%	1 417	1 515	1 670	36%	40%	53%
Japan	-0.1%	-0.6%	-0.6%	125	119	105	92%	93%	95%
Southeast Asia	1.2%	0.8%	0.5%	679	723	787	51%	56%	66%
World	**1.2%**	**0.9%**	**0.7%**	**7950**	**8 520**	**9 681**	**57%**	**60%**	**68%**

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

Sources: UN DESA (2018, 2022); World Bank (2023); IEA databases and analysis.

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 (UN DESA, 2022). In the 2023 GEC modelling cycle, population rises from slightly less than 8 billion in 2022 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 2000-2022 to 0.9% in 2022-2030, 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 this continent to the achievement of the world's sustainable development goals. Around a further quarter is in the Asia Pacific region, where India alone accounts for almost 15% of the growth and becomes the world's most populous country in the near term as China's population growth stalls and reverses.

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 with annual granularity over the projection horizon. By combining this data with the UN population projections an estimate of the rural/urban split may be calculated. In 2022, 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			
	2010-2022	2022-2030	2030-2050	2022-2050
North America	2.0%	1.8%	2.0%	1.9%
United States	2.1%	1.9%	1.9%	1.9%
Central and South America	1.2%	2.3%	2.4%	2.4%
Brazil	0.9%	1.8%	2.3%	2.1%
Europe	1.7%	1.8%	1.4%	1.5%
European Union	1.5%	1.6%	1.1%	1.3%
Africa	2.9%	3.8%	4.0%	4.0%
South Africa	1.2%	1.3%	2.7%	2.3%
Middle East	2.5%	3.0%	3.1%	3.0%
Eurasia	1.9%	1.0%	1.4%	1.3%
Russia	1.4%	0.1%	0.6%	0.4%
Asia Pacific	4.8%	4.1%	2.9%	3.3%
China	6.5%	3.9%	2.4%	2.8%
India	5.7%	6.4%	4.3%	4.9%
Japan	0.6%	0.7%	0.5%	0.6%
Southeast Asia	4.3%	4.6%	3.3%	3.7%
World	**3.0%**	**3.0%**	**2.5%**	**2.6%**

Note: Calculated based on GDP expressed in year-2022 US dollars in purchasing power parity terms.
Source: IEA analysis based on Oxford Economics (2023) and IMF (2023).

Economic growth assumptions for the short to medium term are 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 2023 scenarios, the global economy is assumed to grow by 2.6% per year on average over the period to 2050, with large variations by country, by region and over time (Table 2.2).

The initial years in the *Outlook* are shaped by countries' exposure and resilience to shocks and by where they are currently positioned in the economic cycle. The reverberations from the pandemic and the global energy crisis are being felt across the broader economy as household purchasing power is eroded by higher inflation and as business investment is restrained by rising borrowing costs (although clean energy appears, in some cases, to be bucking this trend). Notwithstanding, labour market conditions remain relatively buoyant: the unemployment rate is at or near its lowest level in half a century in most countries, and this is helping to support household income and economic activity. Global GDP growth over the period to 2030 is projected to average 3%. Partly reflecting these cyclical factors, the range in country and regional growth rates is wider in the period 2022-2030 (6.3 percentage points) than it is in the period 2030-2050 (3.8 percentage points).

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. The way that economic growth plays through into energy demand depends heavily on the structure of any given economy, the exposure and resilience to shocks, the balance between different types of industry, services and agriculture, and on policies in areas such as pricing and energy efficiency.

2.3 Prices

International fossil fuel prices

Table 2.3 ▷ **Fossil fuel prices by scenario**

Real terms (USD 2022)	2010	2022	STEPS 2030	STEPS 2050	APS 2030	APS 2050	NZE 2030	NZE 2050
IEA crude oil (USD/barrel)	103	98	85	83	74	60	42	25
Natural gas (USD/MBtu)								
United States	5.8	5.1	4.0	4.3	3.2	2.2	2.4	2.0
European Union	9.9	32.3	6.9	7.1	6.5	5.4	4.3	4.1
China	8.8	13.7	8.4	7.7	7.8	6.3	5.9	5.3
Japan	14.6	15.9	9.4	7.8	8.3	6.3	5.5	5.3
Steam coal (USD/tonne)								
United States	67	53	46	41	43	26	27	23
European Union	122	290	67	69	68	53	57	43
Japan	142	336	98	77	80	59	65	47
Coastal China	153	205	96	80	79	62	64	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 2023.

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.

CO_2 prices

Table 2.4 ▷ CO_2 prices for electricity, industry and energy production in selected regions by scenario

USD (2022) per tonne of CO_2	2030	2040	2050
Stated Policies Scenario			
Canada	130	150	155
Chile and Colombia	13	21	29
China	28	43	53
European Union	120	129	135
Korea	42	67	89
Announced Pledges Scenario			
Advanced economies with net zero emissions pledges[1]	135	175	200
Emerging market and developing economies with net zero emissions pledges [2]	40	110	160
Other emerging market and developing economies	-	17	47
Net Zero Emissions by 2050 Scenario			
Advanced economies with net zero emissions pledges	140	205	250
Emerging market and developing economies with net zero emissions pledges	90	160	200
Selected emerging market and developing economies (without net zero emissions pledges)	25	85	180
Other emerging market and developing economies	15	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 2023.

CO_2 price assumptions are one of the inputs into the GEC Model as the pricing of CO_2 emissions affects demand for energy by altering the relative costs of using different fuels. There are 73 direct carbon pricing instruments existing today, covering around 40 countries and over 30 subnational jurisdictions. Many others have schemes under development or are considering doing so. All scenarios consider the effects of other policy measures alongside CO_2 pricing, such as coal phase-out plans, efficiency standards and renewable targets. These policies interact with carbon pricing; therefore, CO_2 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 sub-national 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 CO_2 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 CO_2 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, CO_2 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. CO_2 prices are lower, but nevertheless rising, in other emerging economies such as in North Africa, Middle East, Russia and other Southeast Asia. CO_2 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).

End-user prices

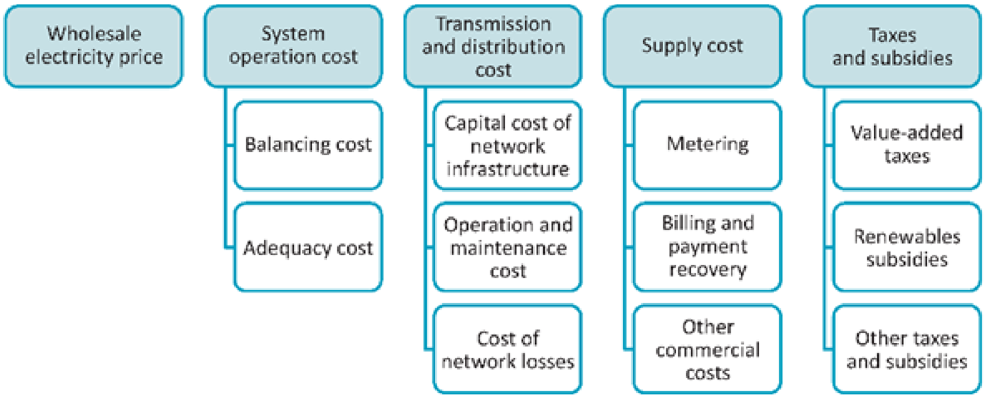
Fuel end-use prices

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 CO_2 prices are calculated 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. 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, an increase of fuel duty on top of CO_2 price 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.

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 CO_2 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[1] 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:

- **Policies and Measures Database:** The IEA's Policies and Measures Database provides access to information on past, existing or planned government policies and measures to reduce GHG emissions, improve energy efficiency and support the development and deployment of renewables and other clean energy technologies. This unique policy database brings together data from the IEA/IRENA Renewable Energy Policies and Measures Database, the IEA Energy Efficiency Database, the Addressing Climate Change database, the Building Energy Efficiency Policies (BEEP) database, and 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 since 1999 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 persistent energy access deficit, 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 WHO.

New policies and measures globally have been considered during the model preparation, including recent announcements 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-2023*.

The considered policies 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.

[1] https://www.iea.org/topics/energy-subsidies

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.

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 STEPS or rather in 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 over 550 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:** newly launched in 2022 and updated in 2023, this provides more detailed tracking of the location, status, capacity, timing and funding of over 350 demonstration projects across the energy sector.
  - **Tracking Clean Energy Progress**: annual tracking of developments 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 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 blast furnace-basic oxygen furnace and direct reduced iron-electric arc furnace (DRI-EAF). The innovative routes are innovative smelting reduction with CCUS, DRI-EAF with CCUS, electrolytic hydrogen-based DRI-EAF and iron ore electrolysis.
- **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 2022 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	
	2022	2030	2050	2030	2050	2030	2050
Iron-based steel production (USD/tpa)							
Conventional	340-500	340-450	360-490	380-630	490-690	440-650	590-740
Innovative		590-770	570-730	590-780	540-700	600-760	570-720
Vehicles (USD/vehicle)							
Hybrid cars	16 800	15 300	15 400	15 200	15 300	15 100	15 200
Battery electric cars	20 500	16 600	14 700	16 100	14 100	15 600	13 700
Batteries and hydrogen							
Hydrogen electrolysers (USD/kW)	1 505	575	445	390	265	315	230
Fuel cells (USD/kW)	115	61	41	52	34	45	30
Utility-scale stationary batteries (USD/kWh)	315	185	140	180	135	175	130

Notes: kW = kilowatt; tpa = tonne per annum; kWh = kilowatt-hour; n.a. = not applicable. All values are in USD (2022).

Sources: IEA analysis; James et. al. (2018); Thompson, et al. (2018); Financial Times (2020); BNEF (2021); Cole et al. (2020); Tsiropoulos et al. (2018); Jato Dynamics (2021).

End-use sectors

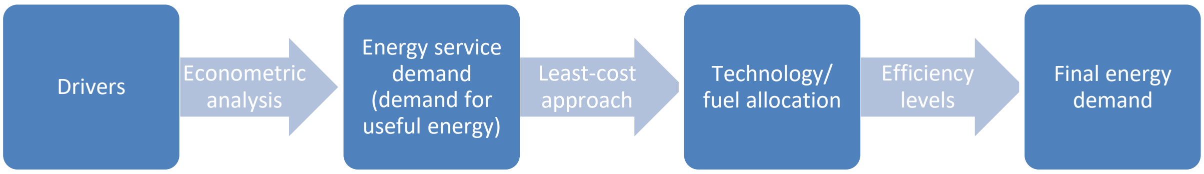
All 29 regions are modelled in considerable sectoral and end-use detail. Specifically:

- **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 socioeconomic 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 CO_2-emitting end-use sector. It accounts for 38% of total final energy consumption and 47% of CO_2 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.

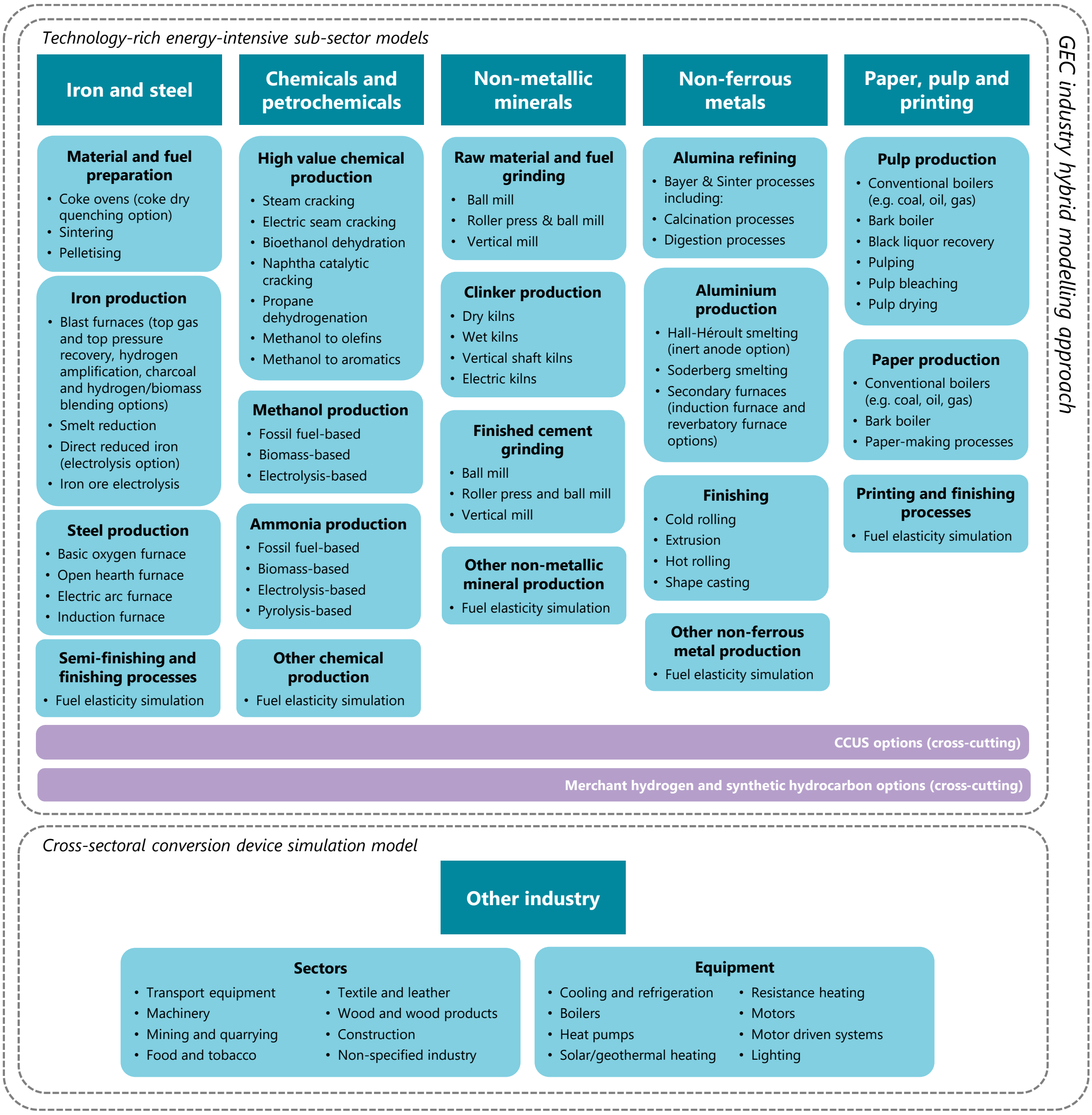
It also covers eight non-energy-intensive sectors: construction; food and tobacco; machinery; mining and quarrying; transportation equipment; wood and wood products; and other industry not specified elsewhere.

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.

Industry model coverage and approach

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. 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.

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



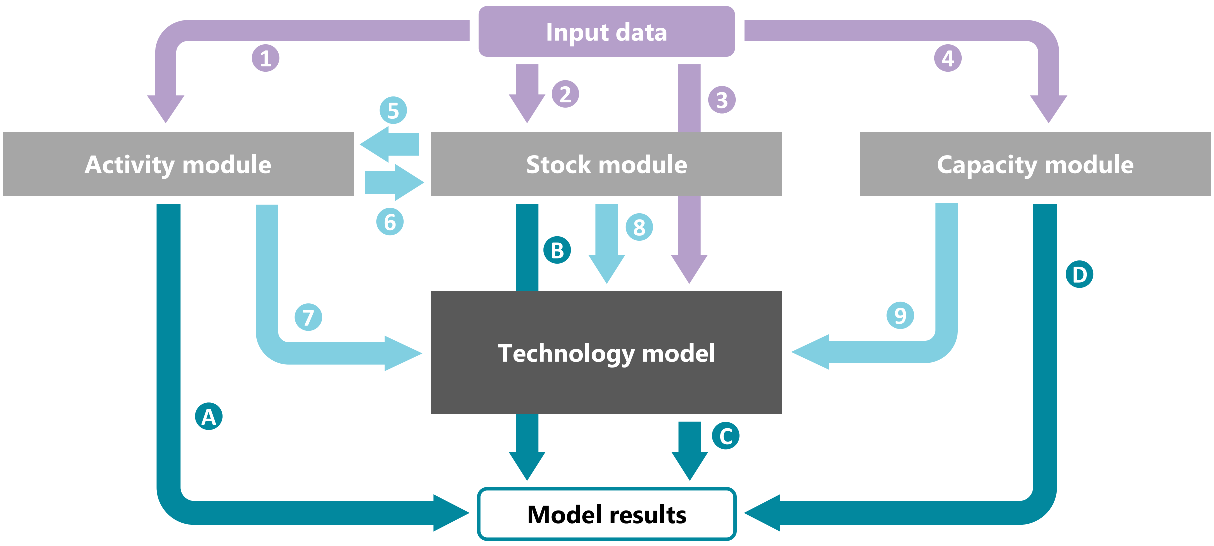
The industry sector is modelled using a hybrid approach (Figure 3.2). Technology-rich simulation models, informed by periodic model runs of the former ETP TIMES optimisation framework, are used for five energy-intensive sub-sectors components thereof (iron and steel; primary chemicals within chemicals 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), the same 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 sections 3.1.3 and 3.1.4 for more information on the approaches taken for each of these main components of the GEC industry model.

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



Notes: Internal industry model flows: 1) Historic production, population projection, industry value-added projection; 2) End-use demand, product lifetimes, process yields, recycling and re-use rates; 3) Energy and raw material intensities, energy prices, CAPEX and OPEX, lifetimes, technology deployment constraints, CO_2 emissions reduction trajectory; 4) Historic and planned capacity, lifetimes, refurbishments; 5) Consumption projections; 6) Material stocks saturation, material efficiency factors; 7) Production projections; 8) Scrap availability; and 9) Residual capacity. Model results: A) Material production; B) Material stocks saturation; C) Energy consumption, CO_2 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. The industry value-added projections inform the rate of 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 2019a). 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 re-use (use of post-consumer materials – without re-melting in the case of metals – for the same or other applications), recycling (increased collection and improved sorting).

Those strategies occurring in the other end-use sectors (e.g. building lifetime extension, vehicle light-weighting) are fed into the stock model via the 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 final or intermediate products) between model regions 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. Global total material demand is thus allocated into regional production based on these current trends.

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.

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, real-world technology progress and the previous ETP TIMES optimisation model. That model used 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 CO_2 emission trajectory that the model must adhere to. Model outputs include energy consumption, fuel combustion and process CO_2 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 "on-site" 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, 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 CO_2 emissions emitted as well as captured and stored.

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, macro-economic 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 macro-economic 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) 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) 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 CO_2 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 CO_2 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 CO_2 prices). Any CO_2 constraints specified by the scenario are also respected.

Industry sector investments

The boundaries for investments reporting include capital expenditure (CAPEX), and engineering, procurement and construction costs. For carbon capture, utilisation and storage (CCUS) technologies, CO_2 transport and storage costs are also included. For material efficiency, investments are based on data on CO_2 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 core industrial equipment CAPEX, 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.

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, 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 CO_2 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 model for road transport, aviation, maritime and rail.

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.[1] Similar historical databases form the basis for modelling rail, international shipping and commercial passenger aviation.

[1] https://www.iea.org/programmes/electric-vehicles-initiative

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 ***A***ctivity, ***S***tructure and ***I***ntensity determine estimates of ***F***uel 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 ***F***uel use
A	vehicle ***A***ctivity (expressed in vehicle-kilometres [*vkm*])
F_i	fuel used by vehicles with a given set of characteristics (***i***) (e.g. segments by service, mode, vehicle and powertrain)
$A_i /A = S_i$	*sectoral* ***S***tructure (same disaggregation level)
$F_i /A_i = I_i$	Energy ***I***ntensity, i.e. average fuel consumption per *vkm* (same disaggregation level)

The parameters monitored include including sales/new registrations of vehicles, secondhand 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).

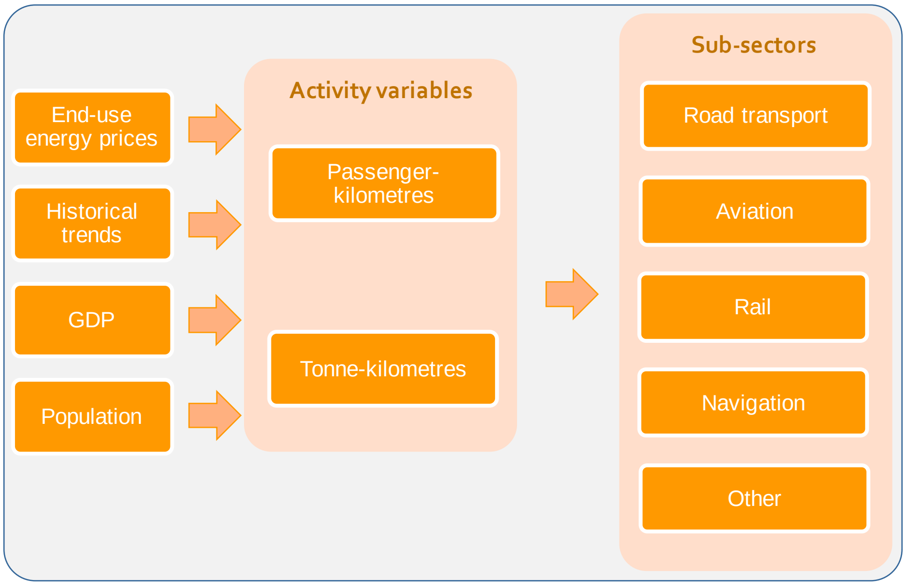
The following parameters are collected and calibrated/validated against the road energy balances on an annual basis:

- 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.

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



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 passenger buses and 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.

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.

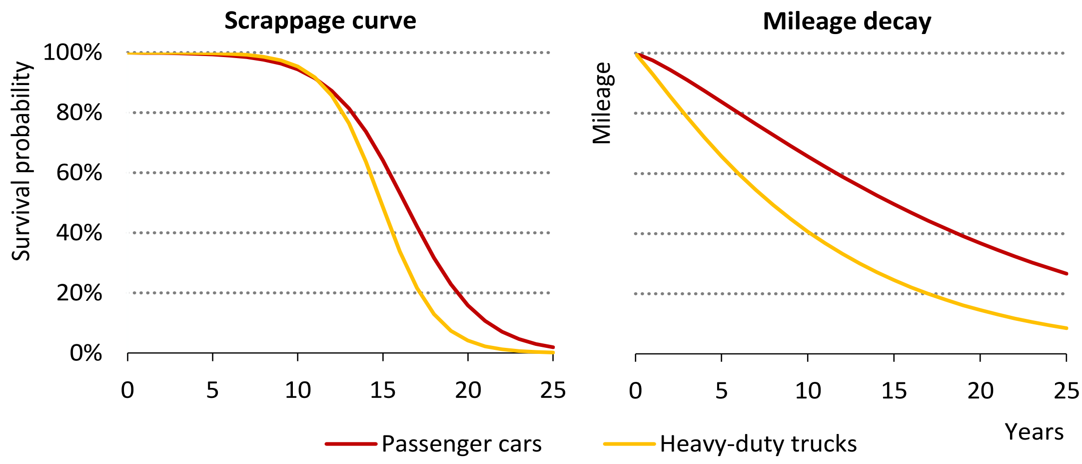
As the largest share of energy demand in transport comes from oil use for road transport, the GEC Model contains technology-detailed sub-models of the total vehicle stock and the passenger car fleet. The stock projection model is based on an S-shaped Gompertz function, proposed in Dargay et al. (2006). This model gives the vehicle ownership based on income (derived from GDP assumptions) and 2 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:

$$V_t = y\, e^{a e^{bGDP_t}}$$

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). The saturation level is based on several country/region specific factors such as population density, urbanisation and infrastructure development. Using the equation above, changes in passenger car ownership over time are modelled, based on the average current global passenger car ownership. 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 and projected road infrastructure developments. 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. Dynamic scrappage function allows to evaluate policy measures, such as early retirement of vehicle (Figure 3.6). To take into account that older vehicles are used less, 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 the total road activity.

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



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.[2] The share of each PLDV type *j* allocated to the PLDV market is given by:

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

Where:

- P_{PLDVj} is the annual cost of a vehicle, including annualised investment and operation and maintenance costs as well as fuel use;

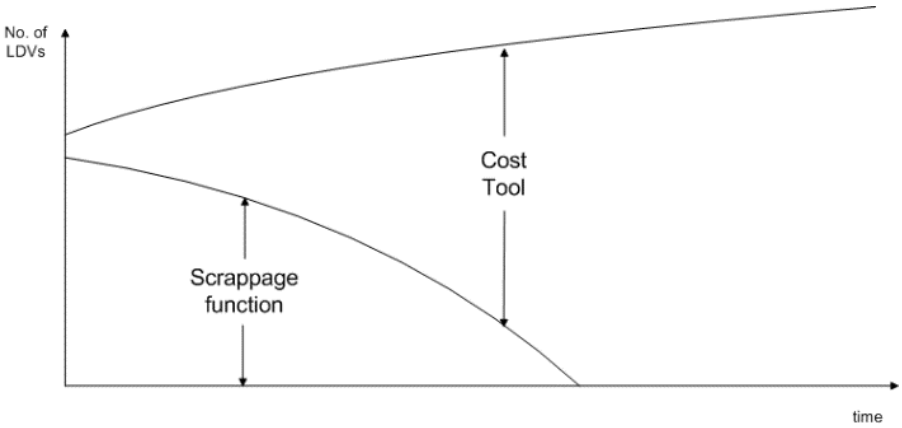
[2] Originally developed to describe the growth of populations and autocatalytic chemical reactions, logit functions can be applied to analyse the stock turnover in different sectors of the energy system. Here, it uses the cost-competitiveness of technology options as an indicator for the pace of growth.

- 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.

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



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 et al, 2017; Krause and Donati, 2018). Regional characteristics and economic factors have been taken into account in order to expand cost curves coverage for all GEC Model regions.

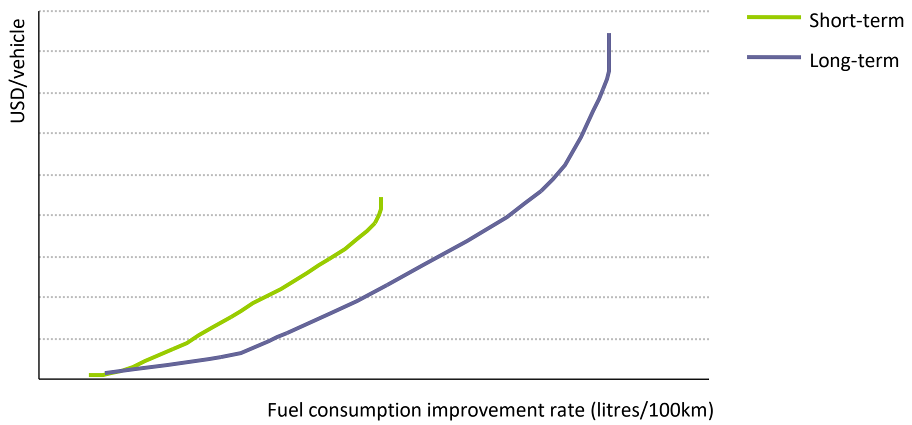
Projected sales of alternative powertrains (and focusing primarily on electric vehicles within light-duty vehicles, and electric and fuel-cell electric vehicles within heavy-duty sectors) for the top 20 global automakers are regularly updated over the course of each year. This analysis permits us to assess whether vehicle manufacturers' commitments for launching new electrified car models are falling behind the necessary 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 are matched to simple projections of battery capacity and (cathode and cell) chemistry, and these projections are linked to bottom-up analyses of battery costs (to 2030), and critical mineral requirements. These projections inform 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* 2023 (IEA, 2023).

Road freight transport vehicles can be broadly classified into light-commercial vehicles (< 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 endogenizes 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



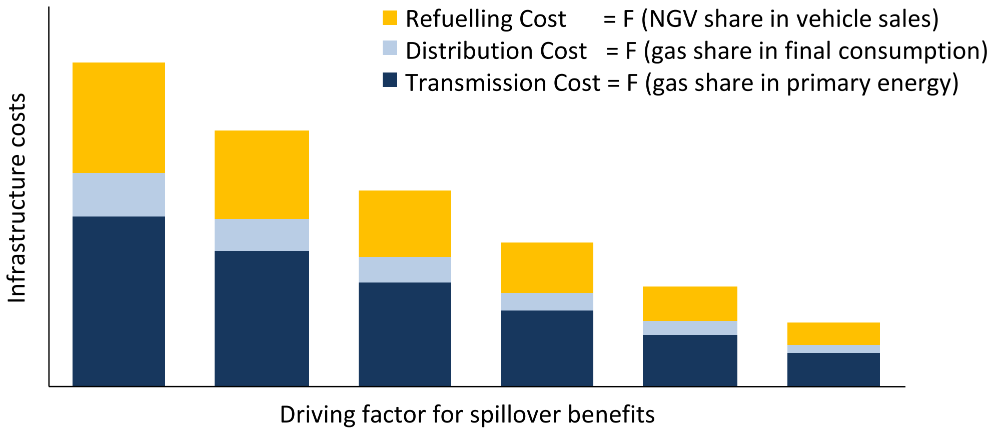
As a second step, the model simulates the cost effectiveness of a conventional ICE vehicle against other competing alternative options. The simulation is guided by the use of a Weibull function. Alternative powertrains for medium- and heavy-duty trucks have been implemented in the GEC Model: fuel cell,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

To assess the problems created due to chicken-and-egg-type of 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)



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 electric vehicle (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. Urban buses are assumed to charge strictly at depots, while intercity buses are assumed to require some share of their electricity demand to be provided outside of the depot. 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 H_2/year) of vehicle category i
- C_i represents the average nameplate capacity (kg H_2/year) of hydrogen refuelling stations serving primarily category i
- U_i represents the average utilisation rate (%) of HRS serving primarily category i

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 CO_2 per kilometre) over the projection period. It further determines incremental investment costs relative to other scenarios and calculates implicit CO_2 prices that guide optimal allocation of abatement in transport.

Aviation

Aviation vehicle and passenger activity 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).[3] 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 (dedicated cargo, general aviation). 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.

The bottom-up modelling of international shipping is based on the ASIF framework (Schipper, 2010) to assess energy demand and CO_2 emissions by region and ship type. Activity projections are developed in co-ordination with the OECD (Environment Directorate) and the International Transport Forum, who provide trade projections by value and weight of different commodity categories. Based on the origin and destination, distance estimates are used to calculate the tonne-km of each commodity type. A share of each commodity type is then allocated to one of the following five categories of ships:

- Liquid bulk carriers (including oil tankers)
- Dry bulk carriers
- Container ships
- General cargo ships
- Other ships

[3] https://www.ucl.ac.uk/energy-models/models/aim

The modelling builds upon external data on vessel stock and sales (UNCTAD and Bloomberg); speed, days at sea, dead weight tonnage and capacity factor (International Maritime Organization [IMO]); and fuel economy (Technical University of Denmark [DTU]). The structure variable is interpreted as the load factor, i.e. the average capacity utilisation per ship per trip, which allows deriving the vehicle-kilometres projected for each region and for each ship type. Load factor projections are based on historically observed growth rates of the average size of the different ship types, which are published by UNCTAD. Fuel economy is based on ship type, dead weight tonnage and capacity factor. Multiplying fuel consumption by the CO_2 emission factors of the different fuels modelled (heavy fuel oil, marine diesel oil, LNG and methanol) gives the total CO_2 emissions.

Rail

The rail module builds off a historical database that covers five different rail types and three fuels across over 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, including plans for rail network extension, primarily high-speed rail. 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 are calibrated with the previous rail module. Behaviour change impact in the rail module is differentiated between high-speed rail (HSR) and non-HSR, also varying by scenario. For HSR, behaviour impacted activity growth considers aviation-to-rail shift informed by countries' Nationally Determined Contribution (NDC). 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.

Behavioural change analysis

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

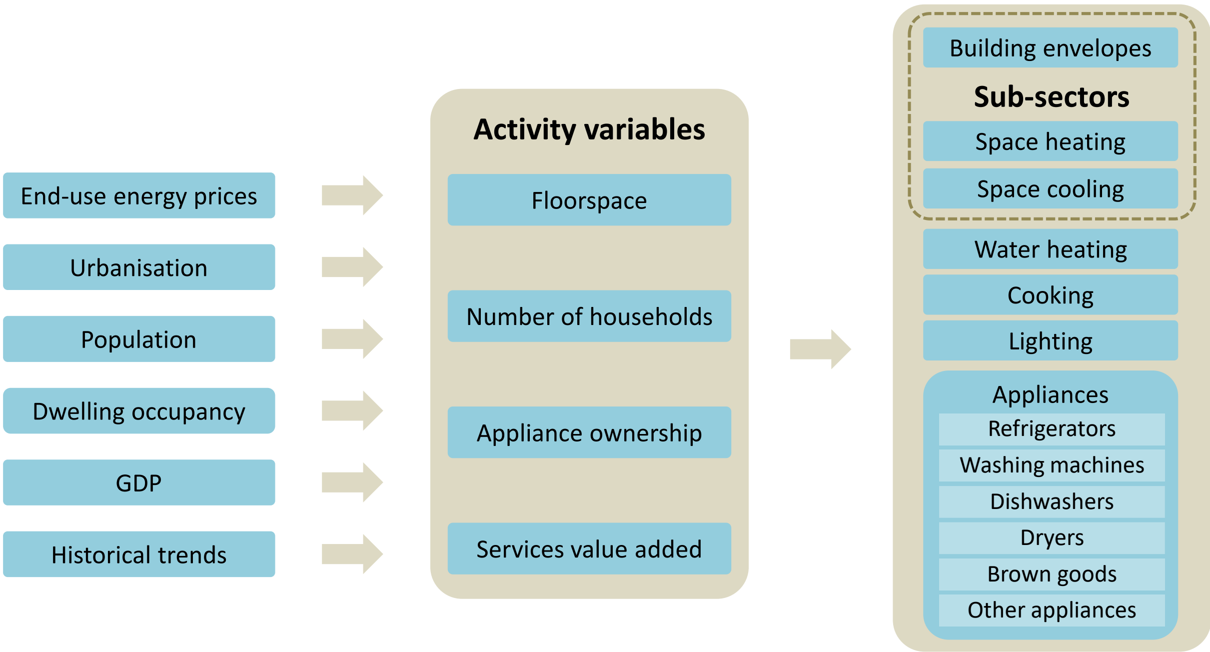
- Ex-post analysis on the impact of behavioural change on the aviation sector has been developed. Historical data (OAG, AIM from UCL) has been used to disaggregate aviation activity per person and distance. Changes in occupancy factors have been assumed to assess the impact of behavioural change in oil 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 need to be 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.
- Regarding 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 3.9). 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 3.9 ▹ Structure of the buildings demand module



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 air conditioners 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:

$$End\ use\ service\ demand = Activity\ variable \times intensity$$

Activity variables refer to the main drivers of energy service demand – for the residential sector, these include floorspace, people per household and appliances ownership; and for the services sector, this includes value added and floorspace. Intensity refers to the amount of energy service (e.g. space heating) needed per unit of the activity variable (e.g. floor space). 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 is 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 the IEA's analysis that is 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 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 building energy codes 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.

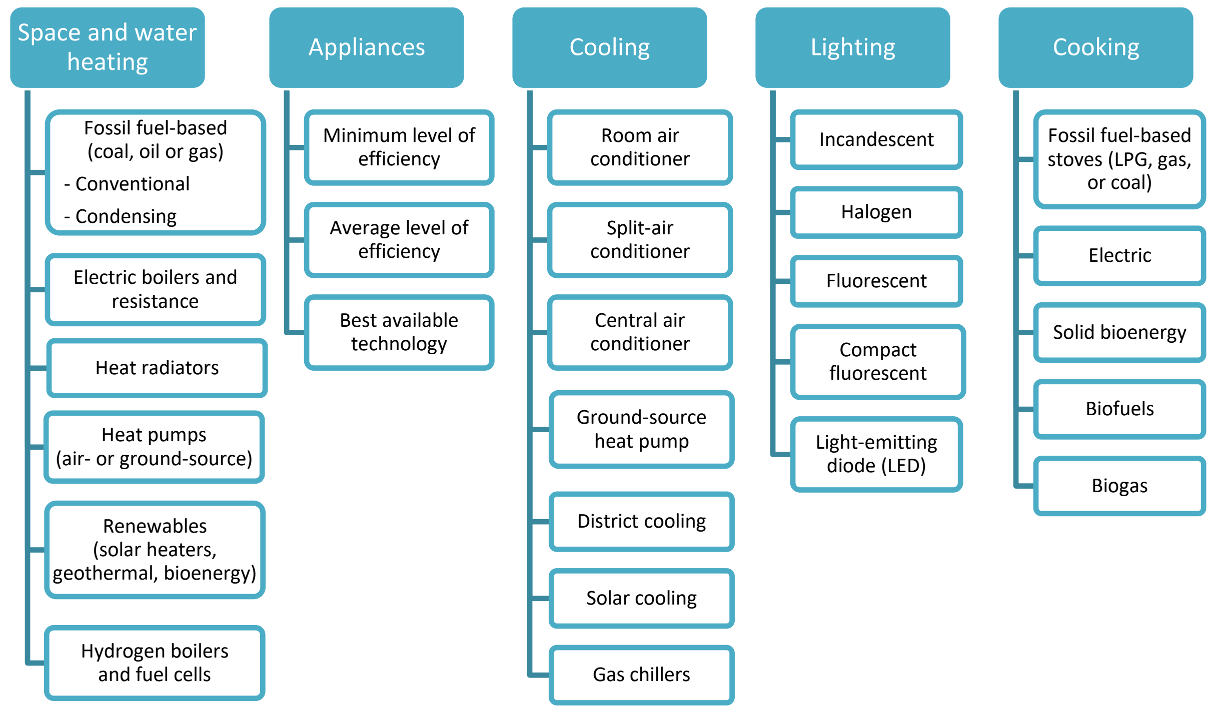
The total energy service demand to be met by space heating or cooling equipment is therefore the sum of the service demand across the different vintages of buildings, determined by the year of construction, and across the five categories of buildings (non-compliant, compliant, zero-carbon-ready, retrofit 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 3.10 ⊳ Major categories of technologies by end-use sub-sector in buildings. 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 the 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 policy constraints in that region. 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 (Anandarajah, *et al.*, 2011; Econoler, *et al.*, 2011; Kannan, *et al.*, 2007; Waide, 2011; LBNL, 2012; GBPN and CEU, 2012).

Figure 3.10 ▷ Major categories of technologies by end-use sub-sector in buildings



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. CO_2, 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).

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

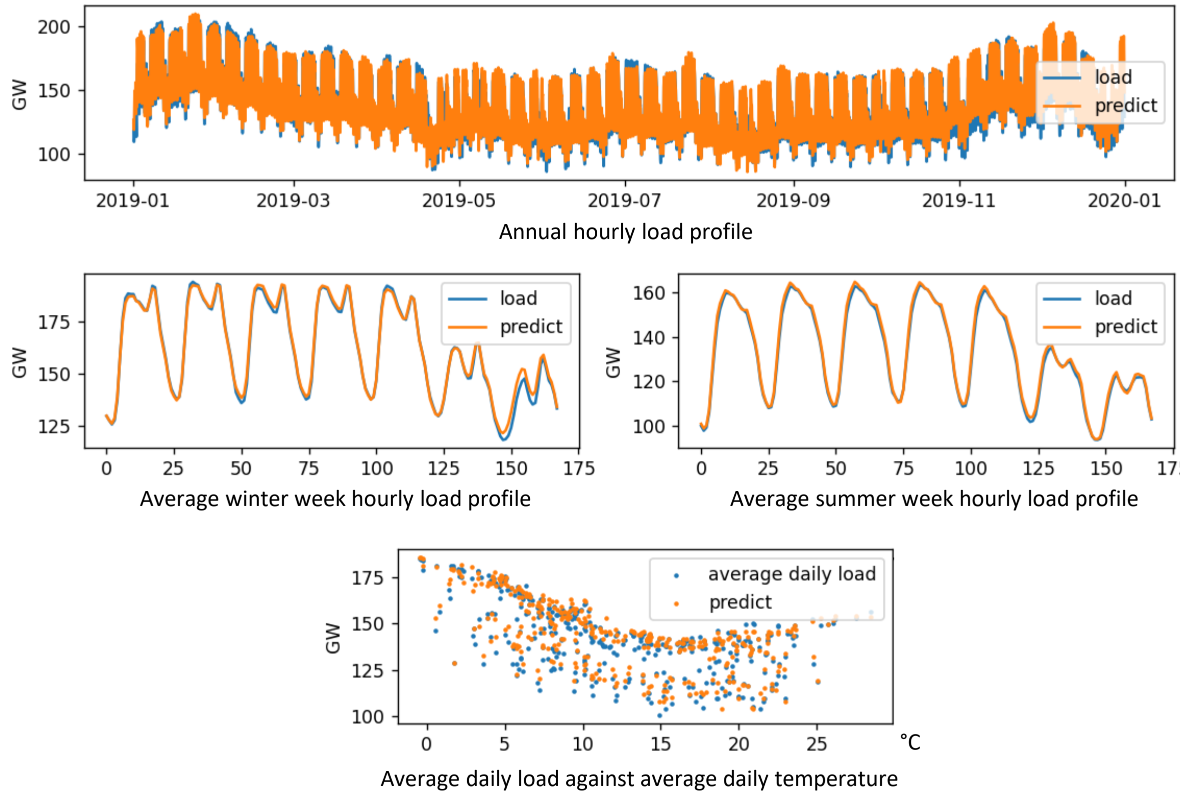
Understanding the hourly, daily and seasonal evolution of electricity demand is critical for accurate modelling of electricity systems, including the assessment of electricity system flexibility needs and the role of demand-side response.

Modelling of hourly electricity demand is undertaken at an end-use level. End-use level modelling 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, impacts 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, 2022a) and temperature timeseries (IEA, 2023). The hourly load dependency to calendar variables and temperature is extracted from regression parameters. The average daily temperature is weighted by population, and temperature thresholds activating cooling and heating demand are determined based on the load response to temperature variations (Figure 3.11). 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 lockdowns.

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 3.11 ▹ Thermosensitivity analysis for hourly load curve assessment



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 3.12.

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 2022, including, among others, China, India, the European Union, the United States and Japan.

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):

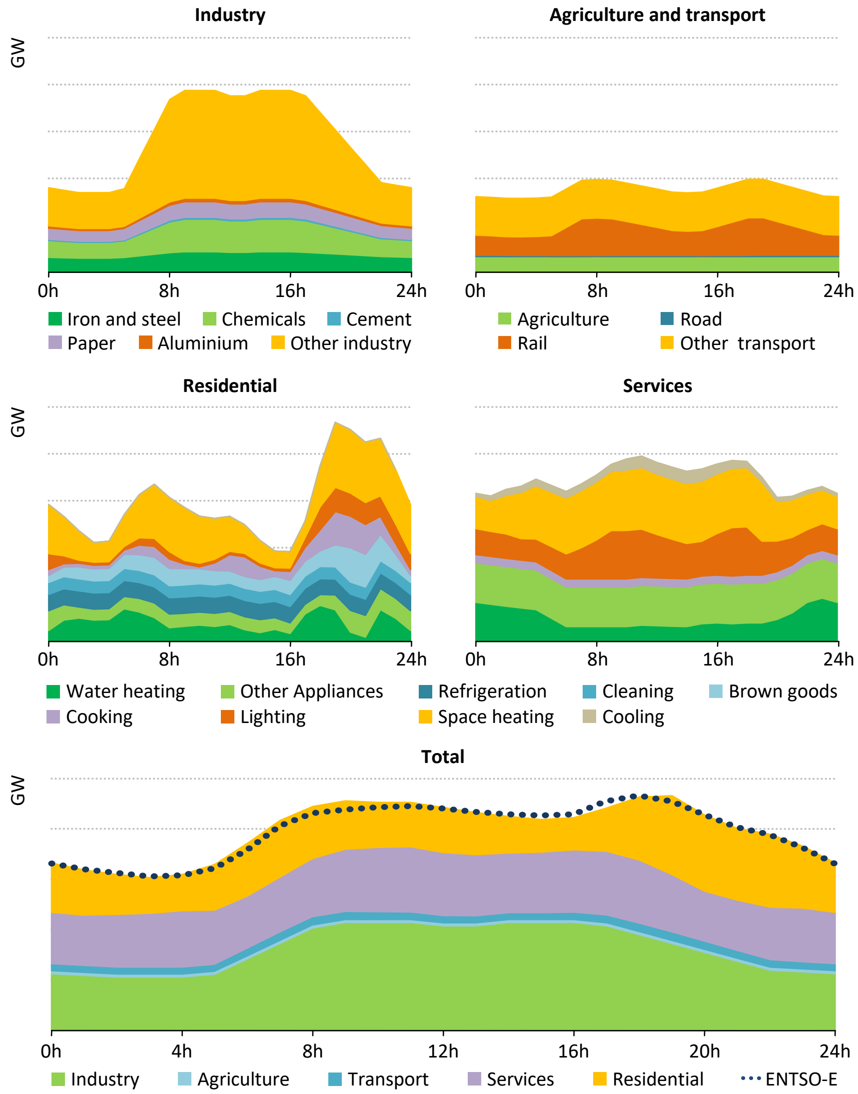
- Shiftability: Share of the load of each end-use that can be shed, shifted or increased by a typical demand response strategy.
- Controllability: Share of the load of each end use which is associated with equipment that has the necessary communications and controls in place to trigger and achieve load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

Figure 3.12 ▷ 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



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, 2016 data.

Electricity generation and heat production

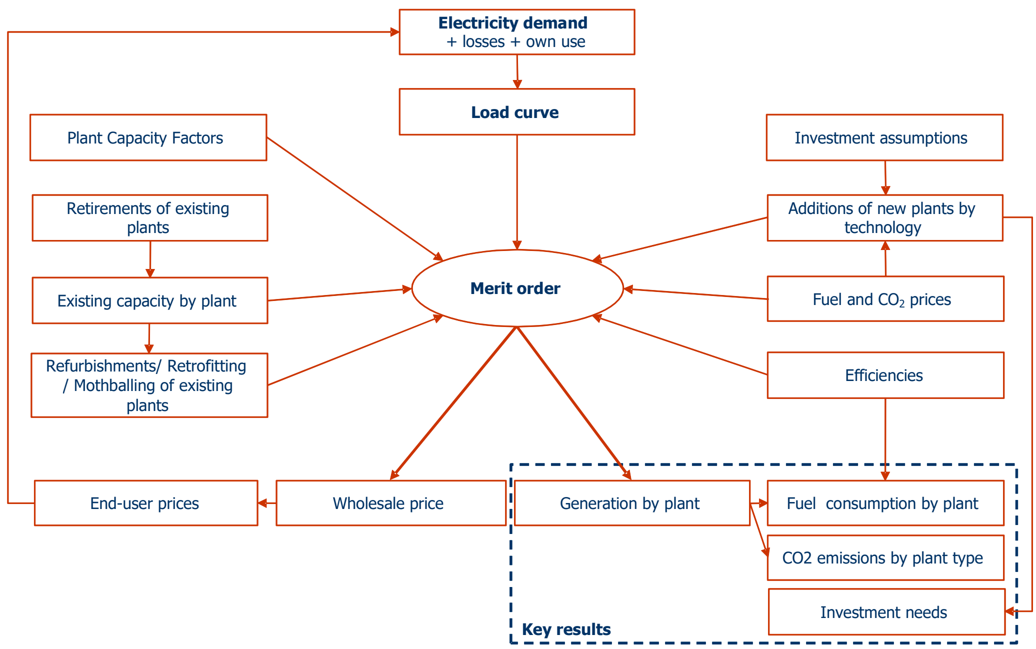
Based on electricity demand, which is computed in all end-use sectors (described in section 3) and other energy transformation sectors – notably hydrogen produced via electrolysis (section 5), the power generation module calculates the following:

- 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.
- CO_2 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.

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 CO_2 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 8% in the OECD and 7% in non-OECD countries unless otherwise specified, for example with revenue support policies, onshore wind and utility-scale solar PV at 3-6% (see financing costs section below), and offshore wind at 4-7% 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.

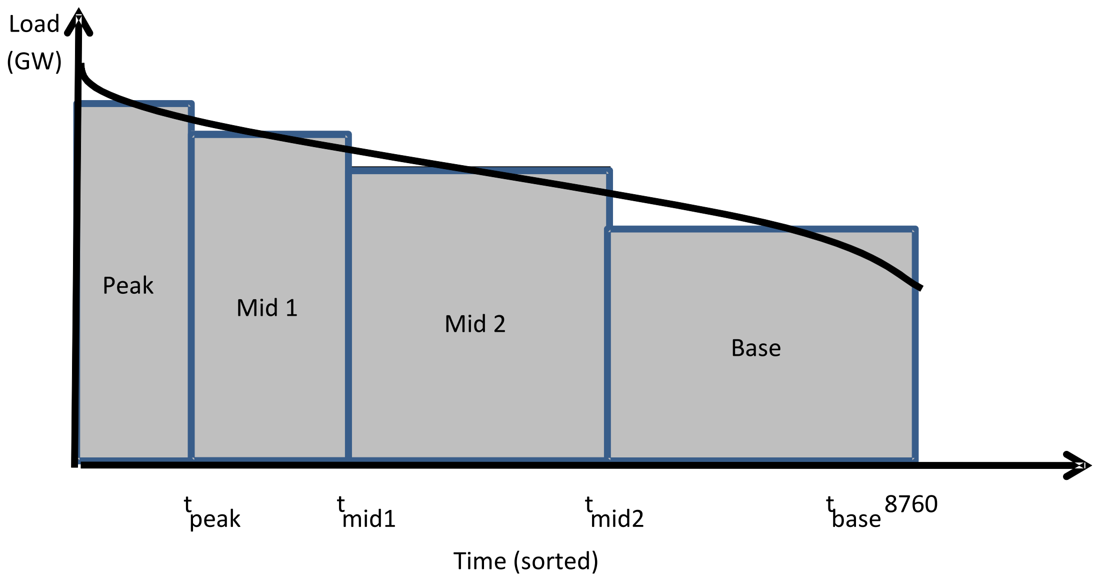
Generation volumes

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.

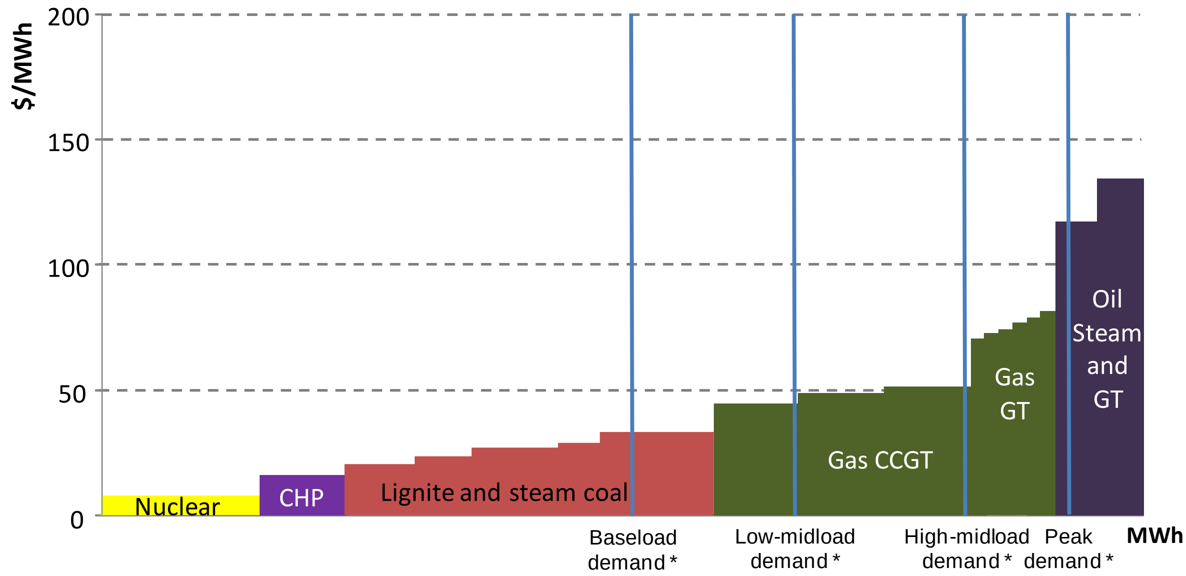
This results in a simplified four-segment load-duration curve for demand (**Figure 4.2**Figure 4.2). This demand must be met by the available power capacity of each region, which consists of variable renewables – technologies like wind and solar photovoltaics (PV) without storage whose output is driven 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



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



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.

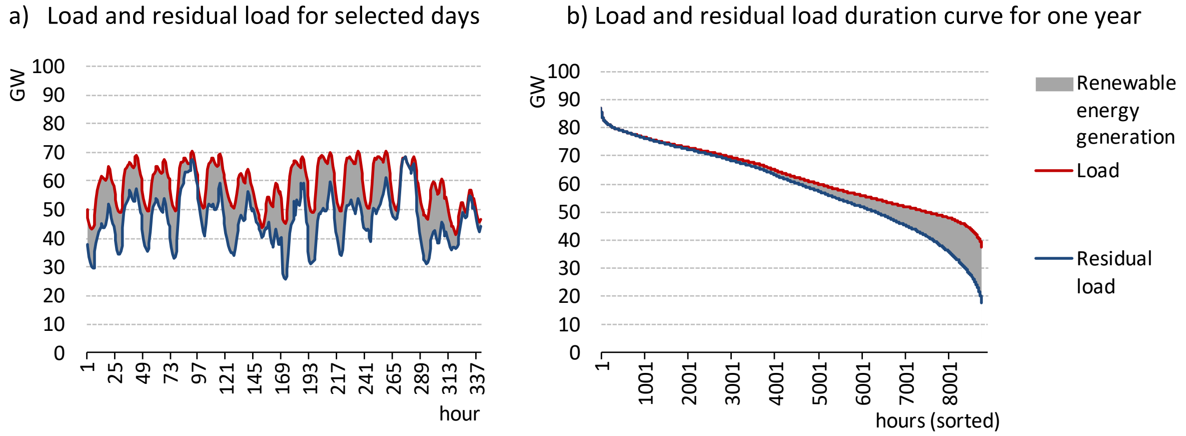
Calculation of the capacity credit and capacity factor of variable renewables

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:

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

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:

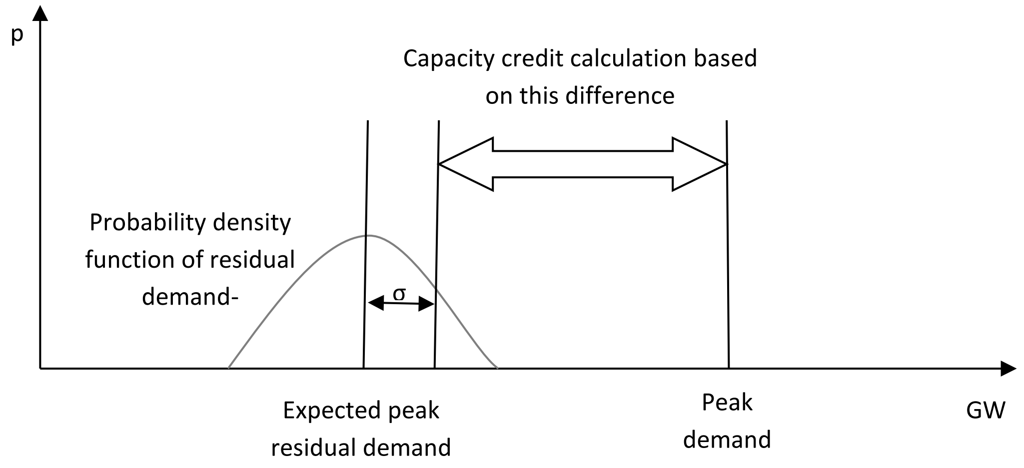
$$Capacity\ credit_{peak} = \frac{Reduction\ Capacity\ Needs_{non-var}}{Capacity_{varRE}} = \frac{\max_t(Load(t)) - \max_t(Residual\ Load(t))}{Capacity_{varRE}}$$

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 first order approach it was assumed that the annual peak residual demand is normally-distributed and calculated the capacity credit 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 re-analysis datasets:

- World Wind Atlas (Sander + Partner GmbH): Global dataset of hourly wind speeds at 10-metre height, 1979-2009, derived from reanalysis data based on climate modelling (Suraniana, 2010)
- Wind supply time-series for the western and eastern United States as derived by WWITS (2010) and EWITS (2011).
- Wind and solar supply time-series for Europe-27 as provided by Siemens AG (Heide, 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, 2010).
- Estimation of solar irradiation based on solar height (Aboumahboub, 2010).

Figure 4.5 ▷ **Exemplary electricity demand and residual load**



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4.2 Value-adjusted Levelised Cost of Electricity

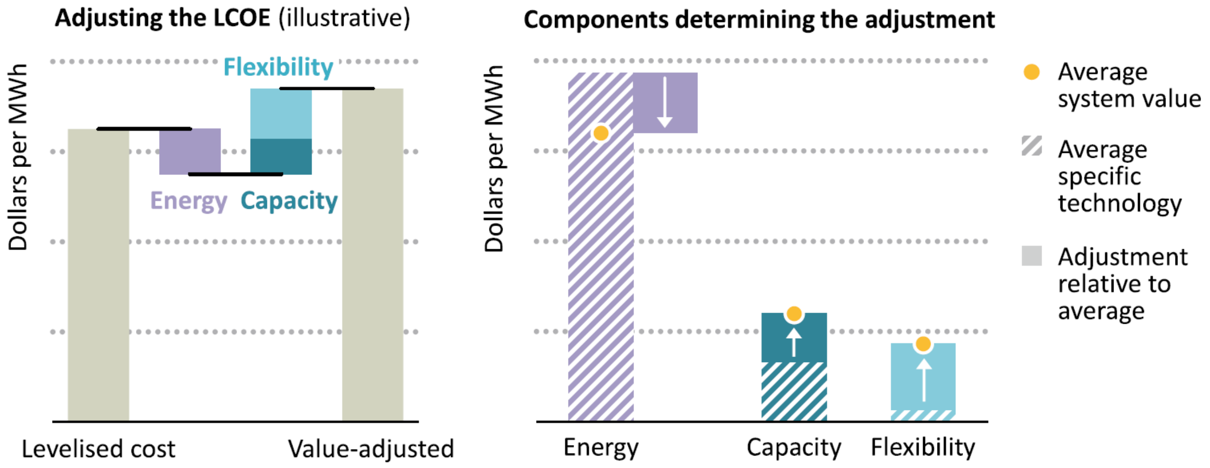
Major contributors to the Levelised Cost of Electricity (LCOE) include overnight capital costs; capacity factor that describes the average output over the year relative to the maximum rated capacity (typical values provided); the cost of fuel inputs; plus operation and maintenance. Economic lifetime 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



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:

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

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:

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

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:

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

- 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 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 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.

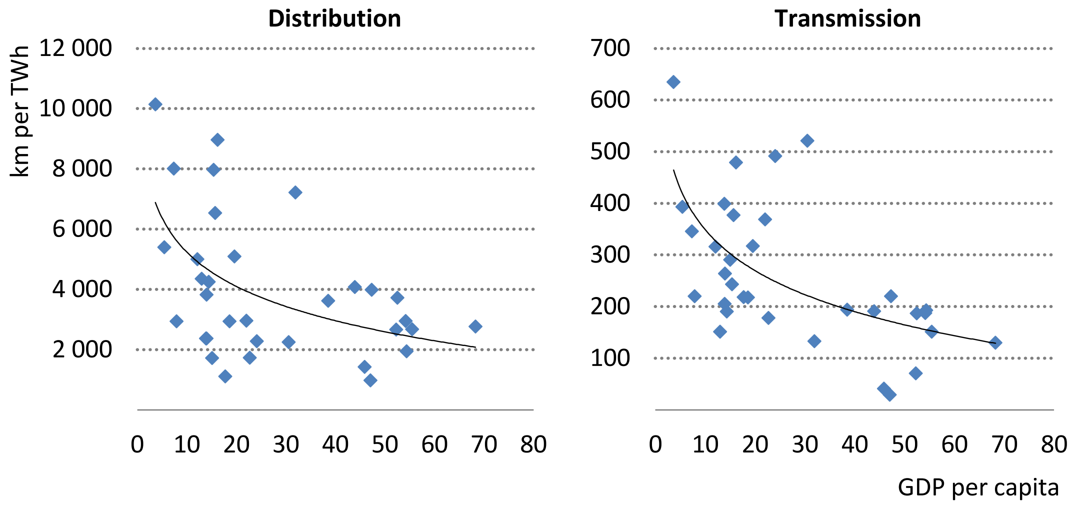
Line replacement due to ageing infrastructure

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



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 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 non-line-length components 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:

$$Annual\ transmission\ investment\ by\ region =$$

$$\sum_{V,P,C} [cost\ new\ lines_{V,P,C} * \begin{pmatrix} \Delta\ electricity\ demand * (\alpha * \ln(GDP\ per\ capita) + \beta) * grid\ composition_{V,P,C} \\ + \sum_{R} (renewables\ additions_R * \gamma_{V,P,C}) \\ + \Delta\ share\ of\ variable\ renewables * \psi * total\ transmission\ length_{V,P,C} \end{pmatrix}$$
$$+ cost\ replacement_{V,P,C} * lines\ replacement_{V,P,C}]$$
$$+ cost\ STATCOM * \phi * \Delta\ share\ of\ variable\ renewables\ installed * total\ power\ capacity$$

$$Annual\ distribution\ investment\ by\ region =$$

$$\sum_{V,P,C} [cost\ new\ lines_{V,P,C} * \begin{pmatrix} \Delta\ electricity\ demand * (\alpha * \ln(GDP\ per\ capita) + \beta) * grid\ composition_{V,P,C} \\ + \sum_{R} (renewables\ additions_R * \gamma_{V,P,C}) \end{pmatrix}$$
$$+ cost\ replacement_{V,P,C} * lines\ replacement_{V,P,C}]$$

Where:

- V is voltage level band
- P is position (overhead, underground)
- C is current (AC or DC)
- R is the renewable energy technology
- $grid\ composition_{V,P,C}$ 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
- $\Delta\ electricity\ demand$ is the annual increase in electricity demand in the region
- $\Delta\ share\ of\ variable\ renewables$ is the annual increase in share of variable renewables in total installed capacity
- $lines\ replacement_{V,P,C}$ 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 model

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 combined heat and power); 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.

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[1] The model works on an hourly granularity, and therefore all 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://beta.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 modelling[3] and is solved using linear optimisation. The optimisation ensures that power plants, energy storage technologies, demand response and electrolysers are operated in a way that minimises the total system cost (thus maximising their utility to the system).

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 years[4] (1987-2016) was obtained from the ERA5 reanalysis dataset of European Centre for Medium-Range Weather Forecasts (ECMWF), 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 electrolysers 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 electrolysers, hydrogen storage and thermal power plants using hydrogen, while considering hydrogen production from off-grid electrolysers 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 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-2023*. 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:

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

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

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, and 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, was also represented to 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 combined heat and power (CHP) are derived in separate sub-modules.

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.

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, concentrating solar power, 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,

[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 (≥10MW) and small (<10MW). Wind: onshore and offshore. Solar PV: large-scale and buildings. Geothermal: electricity only and CHP. Marine: tidal and wave technologies.

or the low emissions 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 such boundary conditions 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 research and development, 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 watt 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, et al., 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-carbon 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 Utility-scale battery storage

Utility-scale 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. 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 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. Similar to other electricity sector technologies, 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.

Utility-scale 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 utility-scale 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 utility-scale batteries, the decline in cost is estimated based on the cumulative capacity additions of utility-scale battery energy storage systems themselves.

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

Other energy transformation

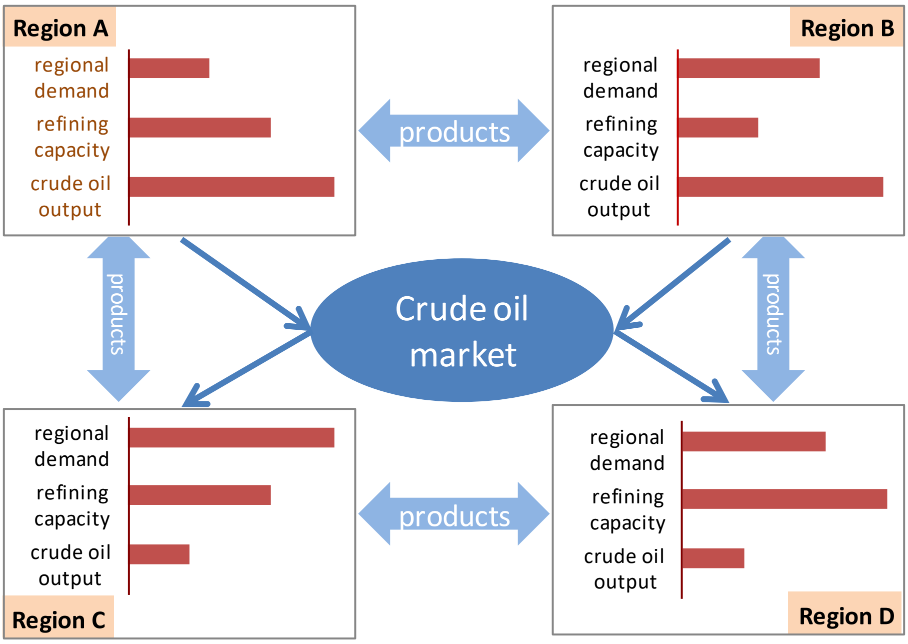
5.1 Oil refining and trade

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 (CDU) 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 2026, 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



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.

Oil supply and demand projections are provided by the GEC Model's fossil-fuel supply and final energy consumption modules. Refineries do not provide for 100% of oil product demand. For the purposes of this analysis, we show the net call on refineries after the removal of biofuels, LPG, ethane and light naphtha from natural gas liquids (NGLs), synthetic liquids from coal-to-liquids (CTL) and gas-to-liquids (GTL) and additives.

The supply-side nomenclature for the refining model is slightly different from the oil supply model. The term "crude oil" used in the model describes all crude oils that have conventional-type quality for processing purposes. This includes conventional crude oil from the supply model, some extra heavy oils that are not diluted or upgraded, tight oil, and synthetic crude from bitumen upgrading processes. Diluted bitumen and condensate are represented as separate streams for intake and trade modelling purposes.

Yields, output and trade are defined for the following product categories: ethane, LPG, naphtha, gasoline, kerosene, diesel, heavy fuel oil and other products (which include petroleum coke, refinery gas, asphalt, solvents, wax, etc). Crude oil trade position and refined products trade balances follow the GEC Model's demand model granularity of 29 individual countries or regions (Figure 5.1).

5.2 Coal-to-liquids, Gas-to-liquids, Coal-to-gas

Coal-to-liquids (CTL), Gas-to-liquids (GTL) and Coal-to-gas (CTG) technologies chemically convert coal and natural gas into other liquid and gaseous hydrocarbons. The Fischer-Tropsch process, for instance, turns coal and natural gas into synthetic fuels through a series of chemical reactions. To that end, an essential first step in this process is to transform coal and natural gas into synthetic gas (also called syngas). Syngas is a mixture of carbon monoxide and hydrogen obtained by coal gasification and the dry reforming of methane. Syngas can also be used to produce methane through the Sabatier reaction and is therefore a means of converting coal into gas.

Countries with large coal or natural gas resources (e.g. China) typically resort to CTL, GTL and/or CTG to bolster their energy security and sovereignty. However, because these technologies are capital-intensive, low-cost coal or natural gas is essential to make the final products competitive. For this reason, the few existing and planned projects remain concentrated in a handful of countries. In the GEC Model, projections are consistent with the status of the projects (e.g. under construction or planned) and are updated every year on a project-by-project basis. Energy-related CO_2 emissions are accounted for and technologies can be fitted with carbon capture, utilisation and storage (CCUS).

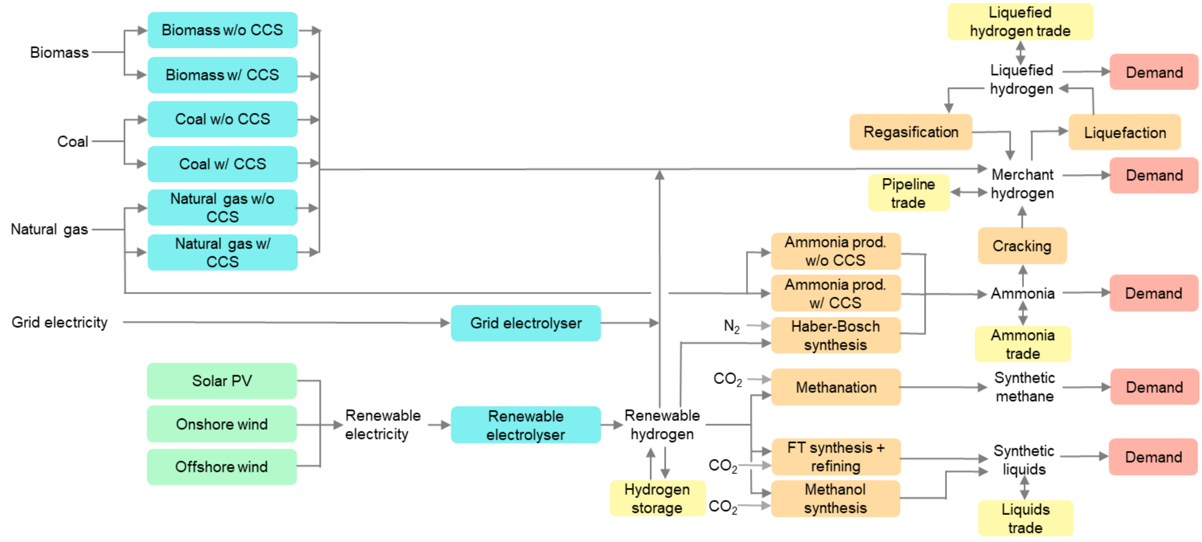
5.3 Hydrogen production and supply

Hydrogen in today's energy system is predominantly used as a feedstock rather than a fuel, especially in all the situations in which it is used as a purified hydrogen gas. These existing applications are mostly in the refining and chemicals sectors and are part of the industry and refining modules of the GEC Model. Most hydrogen for these existing applications is today produced onsite by steam methane reforming of natural gas or coal gasification without CCUS, while in the scenarios an increasing share of this hydrogen is produced over time using technologies that have very low CO_2 intensities, including electrolysis and conversion of fossil fuels equipped with CCUS. This onsite production of hydrogen is modelled within the industry and refining modules of the GEC Model.

The hydrogen production and supply module of the GEC Model covers the production of merchant hydrogen and hydrogen-based fuels. Today, this merchant hydrogen production is complementing onsite hydrogen production in the chemicals and refining sectors. In the scenarios, the use of merchant hydrogen produced from technologies with low CO_2 emissions expands from very low levels today to new applications – including transport, power generation, buildings and industrial heat – contributing to CO_2 emission reductions in these sectors by replacing unabated fossil fuel use. This low-emissions supply is set to become a key part of the future energy transformation sector, alongside power generation and heat and cooling supply.

The merchant hydrogen supply module uses a cost-optimisation modelling framework called TIMES, a technology-rich modelling platform developed and further improved by the ETSAP Technology Collaboration Programme. The hydrogen module depicts various technology options to produce hydrogen and hydrogen-based fuels (ammonia, synthetic methane and synthetic liquid hydrocarbon fuels such as diesel, kerosene and methanol) in terms of existing capacities, conversion efficiencies, fuel costs, operating and maintenance costs, CO_2 emissions as well as CO_2 capture rates for fossil fuel-based technologies and capital costs for new capacity additions. Electrolyser capital costs represent a weighted average of likely deployment shares of different electrolyser technologies, with future cost reductions being derived by component-wise learning curves. Capital costs for all technologies also include all balance-of-plant and engineering, procurement and construction (EPC) costs, which can represent a high share of total installed costs.

Figure 5.2 ▹ Schematic of merchant hydrogen supply module



Based on demands for merchant hydrogen and hydrogen-based fuels from the end-use sectors, electricity and heat generation sector, refineries and biofuel production, the hydrogen supply module determines a least-cost technology mix to cover these demands. Besides these demands and the technical and economic characteristics of technologies, the module takes into account announced hydrogen production or trade projects (using, for example, the IEA's Hydrogen Project Database) as well as policy constraints, such as CO_2 prices or hydrogen deployment targets.

A focus of the model analysis is on low-emissions hydrogen production, i.e. hydrogen produced in a way that does not contribute to an increase in atmospheric CO_2 concentrations. Emissions associated with fossil fuel-based hydrogen production are permanently prevented from reaching the atmosphere and the natural gas supply chain must result in very low levels of methane emissions, or the electricity input to hydrogen produced from water must be from renewable or nuclear sources. There are several complementary pathways to produce low-emissions hydrogen, some of which are mature technologies and some of which are at earlier stages of development. The two dominant pathways in the GEC Model are already demonstrated at commercial scale:

- Fossil fuels with CCUS. The typical technology for producing low-emissions hydrogen from fossil fuels with CCUS is steam methane reforming (SMR) of natural gas equipped with a CO_2 capture unit that captures the overwhelming majority of the CO_2 generated by the SMR process. The hydrogen yield can be improved with water gas shift (WGS) reaction to produce CO_2 and additional hydrogen from carbon monoxide and water.

Adaptations to the SMR process, including autothermal reforming and partial oxidation, can achieve capture rates above 95%. As with other technologies in the GEC Model, cost and performance improvements are assumed to arise from higher deployment levels. The GEC Model accounts for the safe transport and permanent geological storage of the captured CO_2.

- Electrolysis of water using electricity with very low CO_2 intensity. Electrolysers are a well-established technology to split water into hydrogen and oxygen. There are several technologies under development today that can improve existing processes, and these include variations of alkaline electrolysers, polymer electrolyte membrane (PEM) electrolysers and solid oxide electrolyser cells (SOEC). Electrolyser capital costs in the GEC Model aim to represent a weighted average of likely deployment shares of these technologies, which all improve with increased deployment, captured by using component-wise learning curve approaches, and also include all balance-of-plant and EPC costs, which can represent a high share of total installed costs. The module allows the use of grid electricity for hydrogen production, which depending on the grid electricity mix in each region, however, may not necessarily be a low-emissions electricity source. Dedicated renewable electricity generation from solar PV, onshore and offshore wind is modelled as a low-emissions electricity source for hydrogen production. The corresponding renewable electricity generation technologies are characterised by their cost data, capacity factors and resource potentials. The latter two are derived using geospatial analyses, characterising the renewable potential by capacity factor ranges for the model regions.

To reflect the variability of solar PV and wind for hydrogen production, the hydrogen module divides a year in four typical days, which are again divided into eight time slices of three-hour duration. Since this resolution is still too coarse to fully reflect the variability, the ETHOS model suite of the Institute of Energy and Climate Research-3 at Research Centre Jülich, with more detailed time resolution (30 typical periods with 24 typical time slices), has been used. The ETHOS model suite determines, for each location and its hourly solar PV and onshore wind capacity factors, the cost-optimal capacities for solar PV, wind and electrolysers as well as the need for flexibility options, such as hydrogen storage, battery storage or curtailment. This hourly analysis for a single year can take into account operational constraints of subsequent synthesis processes, such as minimum load constraints for Haber-Bosch or Fischer-Tropsch synthesis processes. Applying the model for a grid of raster points in a region and taking into account exclusion zones not available for electricity generation from solar PV and wind allows to derive regional supply cost curves for hydrogen production. These curves are used to inform the regional potentials for hydrogen production from solar PV and wind in the GEC Model.

The production of low-emissions hydrogen-based fuels – including synthetic liquid fuels like synthetic kerosene, diesel, methanol, ammonia and synthetic methane – becomes a key additional component of energy transformation in GEC Model scenarios. The relative ease of transporting hydrogen-based liquid fuels compared with gaseous hydrogen means that demand can be satisfied by imports where this is cost-effective, and in some cases demand for gaseous hydrogen can be met by importing hydrogen-based fuels rather than gaseous hydrogen. In the case of ammonia, it can in some cases be “cracked” at the point of delivery to regenerate gaseous hydrogen. The GEC Model takes these dynamics and options into account to model the trade of gaseous hydrogen via pipelines and of liquid hydrogen, ammonia and synthetic liquid hydrocarbon fuels via ships, with the energy needs and costs for the conversion processes and transport options being considered in the cost-optimisation approach of the hydrogen module.

For carbon-containing hydrogen-based fuels, the carbon input has to come from sources that are compatible with very low CO_2 intensity throughout the supply chain, including co-products, without offsets. In the GEC Model, direct air capture (DAC) and biogenic carbon captured at bioenergy conversion plants are considered as carbon sources.

The hydrogen supply module interfaces with several other modules of the GEC Model. The most notable of these is the electricity generation module, which is both a consumer of hydrogen and hydrogen-based fuels, and also provides electricity (alongside natural gas) to satisfy hydrogen production needs at lowest cost. The results for dedicated renewable electricity generation of the hydrogen module are integrated in the electricity generation module, and feedbacks across this interface are performed iteratively. Demand for hydrogen and hydrogen-based fuels in each sector is determined within each sectoral module, with iterations to update hydrogen supply costs based on overall demand where relevant. To understand the hydrogen infrastructure needs and related investment requirements, an infrastructure tool has been developed, which complements the infrastructure needs for international hydrogen trade from the hydrogen module by analysing the domestic infrastructure needs within regions, in particular for pipelines (new or repurposed natural gas pipelines) and storage.

5.4 Biofuel production

Bioenergy is an important renewable energy option in all its forms: solid (biomass), liquid (biofuels) and gas (biogas and biomethane). The bioenergy supply module determines primary bioenergy availability (see Section 6.4). For liquid and gaseous uses, bioenergy is transformed prior to final use in the liquid biofuels and biogas and biomethane supply modules.

The liquid biofuels supply module builds upon previous modelling work for the WEM and ETP models and is designed to assess the deployment of liquid biofuel conversion technologies required to meet demand in the end-use sectors of transport, industry, buildings and agriculture from a variety of biomass feedstocks that are coherent with both the bioenergy supply module and the biogas and biomethane supply module. The module calculates conversion losses, energy input requirements and investment spending, and assesses the amount of liquid biofuels production associated with CCUS.

The biogas and biomethane supply module is designed to assess the sustainable technical potential and costs of biogas and biomethane for all GEC Model regions. This analysis includes feedstocks that can be processed with existing technologies, that do not compete with food for agricultural land, and that do not have any other adverse sustainability impacts (e.g. reducing biodiversity). Feedstocks grown specifically to produce biogas, such as energy crops, are also excluded. The module excludes international trade of biogas and biomethane.

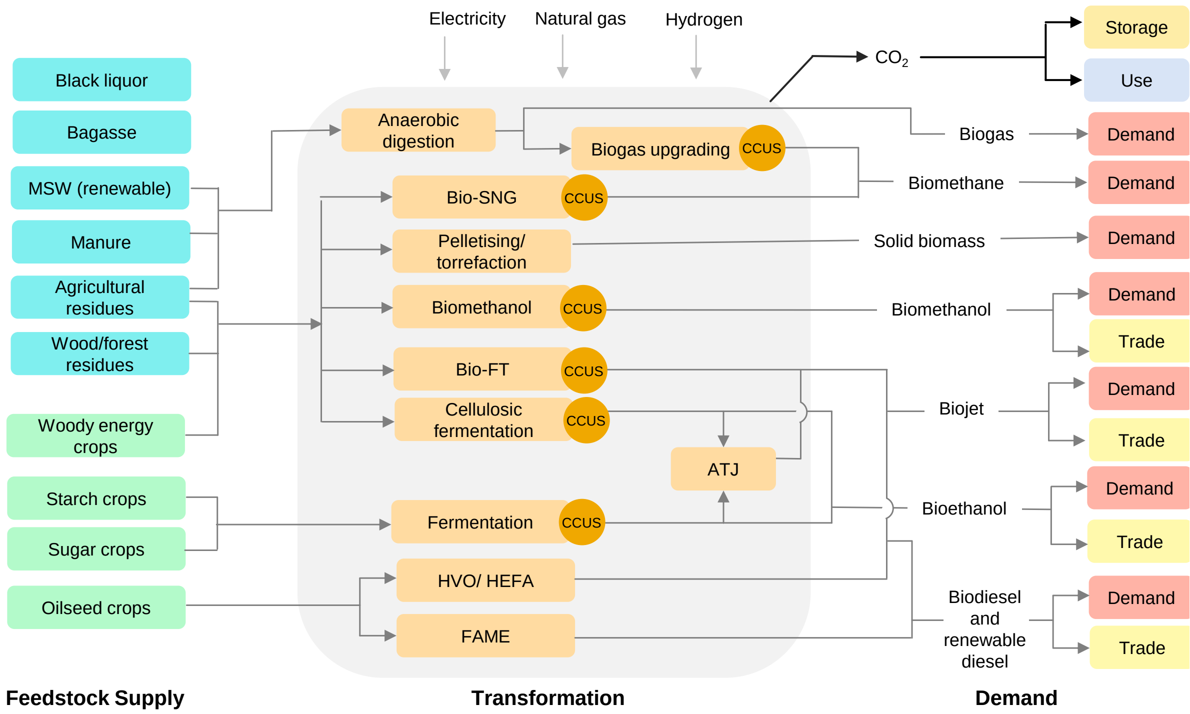
Liquid biofuel supply module

Liquid biofuels today are mainly produced using commercially available technologies that convert food-based energy crops into so-called conventional biofuels. Technologies include ethanol production from starch and sugar, fatty acid methyl ester (FAME) biodiesel, and hydrotreated vegetable oil (HVO) renewable diesel. In the modelled scenarios, an increasing share of liquid biofuels are produced from advanced conversion technologies (such as biomass gasification and Fischer-Tropsch synthesis or cellulosic ethanol production) and from advanced feedstocks such as waste and residue oils, forestry residues, crop residues, and non-food energy crops grown on non-arable, marginal land. Advanced feedstocks do not compete with food and feed, and minimise negative environmental impacts on soil health, water resources and biodiversity.

The liquid biofuels supply module uses a cost-optimisation modelling framework called TIMES, a technology-rich modelling platform developed and further improved by the ETSAP Technology Collaboration Programme of the IEA. The liquid biofuels module depicts various technology options to produce liquid biofuels (ethanol, biodiesel and renewable diesel, biojet kerosene and biomethanol) with and without carbon capture, in terms of existing capacities, conversion efficiencies, fuel and feedstock costs, operating and maintenance costs, CO_2 emissions as well as CO_2 capture rates and capital costs for new capacity additions. Liquid biofuel capital costs represent the latest data available from industry and academia, with future cost reductions assessed using learning curves. A variety of biomass feedstocks are included in the model, such as forestry residues, crop residues, and non-food energy crops. These biomass feedstocks are coherent with the bioenergy supply module and the biogas and biomethane supply module. The liquid biofuels module also models liquid biofuel trade for ethanol, biodiesel and renewable diesel, biojet kerosene and biomethanol between each GEC Model region (see Section 6.4).

Based on demand for liquid biofuels from the end-use sectors, the liquid biofuel supply module determines a least-cost technology mix to cover these demands. Besides these demands and the technical and economic characteristics of technologies, the module takes into account announced biofuel production and trade projects as assessed by the IEA's *Renewable Energy Market* reports, as well as policy constraints, such as CO_2 prices, biofuels subsidies or targets for advanced biofuels production.

Figure 5.3 ▷ Schematic of liquid biofuels model



Notes: ATJ = alcohol-to-jet; CCUS = carbon capture, utilisation and storage; FAME = fatty acid methyl ester; FT = Fischer-Tropsch; HEFA = hydroprocessed esters and fatty acids; HVO = hydrotreated vegetable oil; MSW = municipal solid waste; SNG = synthetic natural gas. Bio-hydrogen production is included in merchant hydrogen module (see Section 5.3).

The liquid biofuels module includes the following conversion pathways for each liquid biofuel product:

- **Ethanol** is produced from conventional fermentation processes using starch (e.g. corn) or sugar (e.g. sugar cane) crops, or from an advanced fermentation process using cellulosic feedstocks (e.g. corn stover), in which the feedstock must first undergo a process to break down the feedstock and release the sugars prior to fermentation.
- **Biodiesel and renewable diesel.** Conventional biodiesel is produced from the FAME conversion process, while advanced renewable diesel is produced from the HVO process as well as the thermochemical process of biomass gasification followed by Fischer-Tropsch synthesis.
- **Biojet kerosene** is produced from either the HVO process (also known as hydroprocessed esters and fatty acids, or HEFA), thermochemically from biomass gasification and Fischer-Tropsch synthesis, or from conventional and advanced ethanol using the alcohol-to-jet (ATJ) pathway.
- **Biomethanol** is produced thermochemically from the biomass gasification and methanol synthesis pathway.

Additionally, several liquid biofuel production pathways can be deployed with carbon capture for use or storage. These include conventional and advanced ethanol routes, renewable diesel and biojet kerosene from biomass gasification and Fischer-Tropsch synthesis, and biomethanol from biomass gasification and methanol synthesis. Captured CO_2 is either stored, creating so-called carbon removals, or used for the production of synthetic hydrocarbon fuels in the hydrogen module.

Biogas and biomethane supply module

Biogas and biomethane supply potential has been assessed considering a wide variety of feedstock, grouped in six categories: crop residues, animal manure, municipal solid wastes, forest product residues, wastewater and industrial wastes.

The feedstock supply potentials are built on a wide range of data originating largely from the Food and Agriculture Organization of the United Nations (FAO) database and OECD-FAO study (OECD/FAO, 2018) for wheat, maize, rice, other coarse grains, sugar beet, sugar cane, soybean, and other oilseeds, cattle, pig, poultry and sheep, log felling residues, wood processing residues and distiller dried grains, a by-product of ethanol production from grains and from a World Bank study (World Bank, 2018) for different categories of organic municipal solid waste such as food and green waste, paper and cardboard, and wood. Wastewater includes only municipal wastewater and is based on the output data from the Water module previously developed by the *World Energy Outlook* team.

Biogas is produced by anaerobic digestion. Five technologies of centralised biogas production plants are modelled: landfill gas recovery system, digester in municipal wastewater treatment plant and three centralised co-digestion plants (small-, medium and large-scale). In addition, two types of household-scale digester are modelled in the residential sector of the GEC Model, to account for rural and decentralised biogas production in rural areas of developing economies.

For biomethane, two production pathways are considered: upgrading of biogas produced by anaerobic digestion and thermal gasification and methanation of lignocellulosic biomass.

For each technology, technical and economic parameters, e.g. efficiency, lifetime, overnight capital cost or operational costs, are collected to assess the production costs.

The combination of the assessment of the supply potential and the economic evaluation of the different biogas and biomethane processes were used to assess biogas and biomethane supply cost curves. For a given year, it is made of the aggregation of biomethane potential and associated levelised cost of production for every region, feedstock and technology. Information provided by supply curves is then used to assess the cost-competitiveness of the two main uses of biogas and biomethane: electricity and heat generation and injection in the gas grid. Supply curves are used to calculate GHG emissions potential savings and related abatement cost to understand the future role of carbon pricing on biogas and biomethane development.

Energy supply

6.1 Oil

The purpose of this module is to project the level of oil production in each country through a bottom-up approach[1] that builds on:

- The historical time series of production by countries.
- Standard production profiles and estimates of decline rates at field and country levels derived from the detailed field-by-field analysis first undertaken in *WEO-2008* and updated since.
- An extensive survey of upstream projects sanctioned, planned and announced over the short term in both OPEC and non-OPEC countries, including conventional and non-conventional reserves, as performed by the IEA Oil Market Report team; this is used to derive production in the first 5 years of the projection period (a summary of the differences in methodology between the GEC Model and the *Medium-Term Oil Market Report* is explained in Box 6.1).
- A methodology, which aims to replicate as far as possible the decision mode of the industry in developing new reserves by using the criteria of net present value of future cash flows (Figure 6.1).
- A set of economic assumptions discussed with and validated by the industry including the discount rate used in the economic analysis of potential projects, finding and development costs, and lifting costs.
- An extensive survey of fiscal regimes translating into an estimate of each government's take in the cash flows generated by projects.
- A comprehensive assessment of various financial risks (e.g. geopolitics, rule of law, regulatory oversight) to represent the attractiveness of investment in oil and natural gas fields.
- Values of remaining technically recoverable resources (Table 6.1) calculated based on information from the United States Geological Survey (USGS), BGR and other sources.

The paragraphs below describe how the USGS data are used in the GEC Model. USGS publishes its World Petroleum Assessment, a thorough review of worldwide conventional oil and gas resources. In it, USGS divides the resources into three parts:

- Known oil, which contains both cumulative production and reserves in known reservoirs.
- Undiscovered oil, a basin-by-basin estimate of how much more oil there may be to be found, based on knowledge of petroleum geology.
- Reserves growth, an estimate of how much oil may be produced from known reservoirs on top of the known reserves. As the name indicates, this is based on the observation that estimates of reserves (including cumulative production) in known reservoirs tend to grow with time as knowledge of the reservoir and technology improves. For the 2000 assessment, reserve growth as a function of time after discovery was calibrated from observation in US fields, and this calibration applied to the known worldwide reserves to obtain an estimate of worldwide reserves growth potential.

Since the 2000 assessment, USGS has regularly published updates on undiscovered oil in various basins, and these were considered in the GEC Model. In 2012, USGS published an updated summary of worldwide undiscovered oil, as well as a revised estimate for reserves growth based on a new field-by-field method focused on the large fields in the world. Previously, the known oil estimates used by the USGS when generating its reserve

[1] "Bottom-up" in this context means "based on field-by-field analysis".

growth estimates had not been released publicly. However, a recent report provides its assumptions, albeit aggregated at a global level (USGS, 2015). The USGS estimate of cumulative production and reserves outside the United States is 2 060 billion barrels, in close alignment with the IEA equivalent estimate of 2 050 billion barrels. For conventional oil, the USGS estimates of undiscovered oil and reserves growth published in 2012 provide the key foundation for the values used in GEC Model. The GEC Model estimates of remaining technically recoverable resources combine USGS undiscovered, USGS reserves growth and IEA estimates for known. Similar analysis, based on the same USGS publications, feeds into the IEA NGLs and natural gas resources database, which allows an evaluation of total conventional liquid hydrocarbons resources and conventional gas resources.

Box 6.1 ▹ Methodological differences between the GEC Model and the IEA *Medium-Term Oil Market Report*

Every year, the IEA publishes projections of oil supply and demand for the next five years in the *Medium-Term Oil Market Report* (MTOMR), and for the next two and half decades in the GEC Model. These two sets of projections use different methodologies that evolve over time, such that comparisons are not necessarily straightforward. This box summarises the key differences.

A key difference between the MTOMR and the GEC Model is the oil price assumption. The MTOMR assumes that the oil price follows the futures market curve at the time of publication. This is then used for demand projections, and supply is assumed to follow, with OPEC filling the gap between field-by-field projections of non-OPEC supply and demand. By contrast, the GEC Model determines the equilibrium price that brings supply and demand in balance. (This equilibrium is performed as a trend and not year-by-year to avoid generating investment/price cycles which would obscure policy effects and long-term trends.)

The GEC Model relies on the field-by-field analysis underlying the MTOMR to guide production by country in the first 5 years of the projection period. The country-by-country methodology is also extended to OPEC countries, so that OPEC is not treated as the swing producer, though constraints thought to represent possible OPEC policies are incorporated in the GEC Model oil supply module.

Results are also often presented slightly differently in the two reports, including in terms of the groupings for conventional and unconventional oil. The GEC Model includes all Canadian oil sands and Venezuelan Orinoco production as unconventional oil, while the MTOMR generally counts only upgraded bitumen or extra-heavy oil as unconventional.

In analysing and projecting oil demand, the GEC Model and MTOMR have methodological differences. Since the GEC Model is concerned with projections of supply and demand of all energy sources and projects a world energy balance in the future, it incorporates all demand components. While the GEC Model incorporates statistical differences and refinery transformation losses into historical demand values and projects those into the future, MTOMR’s demand definition does not include these two categories in its historical values and projections.

The GEC Model also splits biofuels from historical oil demand and projects oil demand and biofuels demand separately. OMR does not separate biofuels from historical oil demand, and oil demand is projected with a mix of biofuels. As a result, one barrel of oil from MTOMR projections has lower energy content than one barrel in the GEC Model if biofuels are projected to grow. A direct comparison of GEC Model and OMR results is thus only possible if biofuels are stripped from MTOMR oil demand values.

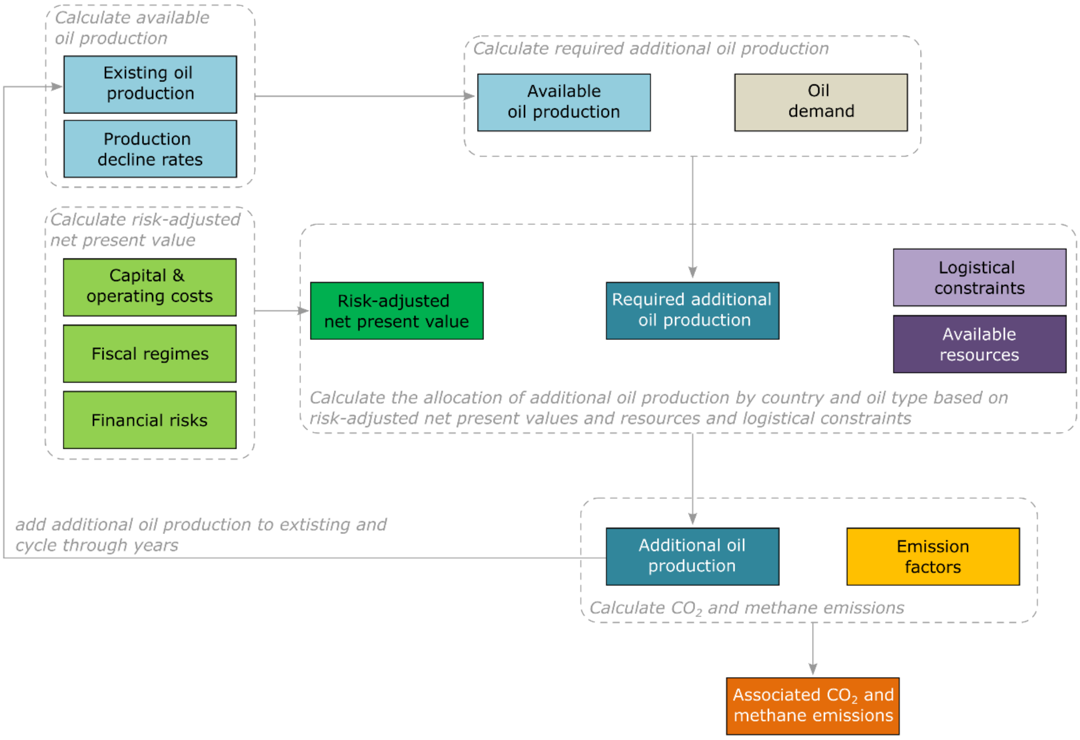
The differences in refining mainly concern the interpretation of installed capacity. The GEC Model discounts most of the idled capacity of Chinese teapot and smaller refineries that run below 30% utilisation rates. It also discards mothballed capacity in its entirety, even if the owner of the refinery has announced that it is a temporary economic shutdown. The GEC Model and the MTOMR may also differ in their projection of firm capacity additions within the same timeframe.

Each country's projected oil production profile is made of six components. Conventional crude oil fields are also distinguished by water depth (onshore, shallow [water depth less than 450 metres], deepwater [between 450 and 1 500 metres] and ultra-deepwater [greater than 1 500 metres]). For unconventional oil, extra-heavy oil and bitumen is also distinguished by mining or *in situ* technologies and tight oil by play productivity.

- Production from currently producing fields as of an estimated end-2021: the projected decline rates in each country are derived from the analysis summarised in Box 6.1.
- Production from discovered fields with sanctioned, planned and announced developments.
- Production from discovered fields awaiting development.
- Production from fields yet to be discovered.
- Production of natural gas liquids.
- Production of unconventional oil.

Trends in oil production are modelled using a bottom-up methodology, making extensive use of our database of worldwide ultimately technically recoverable resources. The methodology aims to replicate investment decisions in the oil industry by analysing the profitability of developing reserves at the project level (Figure 6.1).

Figure 6.1 ▷ Structure of the oil supply module



In the GEC Model oil supply module, production in each country or group of countries is derived separately, according to the type of asset in which investments are made: existing fields, new fields and non-conventional projects. Standard production profiles are applied to derive the production trend for existing fields and for those new fields (by country and type of field) which are brought into production over the projection period.

The profitability of each type of project is based on assumptions about the capital and operating costs of different types of projects, and the discount rate, representing the cost of capital. The net present value of the cash flows of each type of project is derived from a standard production profile. Projects are prioritised by their net present value and the most potentially profitable projects are developed. Constraints on how fast projects can be developed and how fast production can grow in a given country are also applied. These are derived from historical data and industry inputs. When demand cannot be met without relaxing the constraints, this signals that oil prices need to be increased.

US tight oil model

A tight oil module is part of GEC Model, originally developed for *WEO-2016*, and it explores the sensitivity of production of tight oil in the United States to changes in price and resource availability. The module projects possible future production across 23 shale plays, taking into account the estimated ultimate recovery (EUR), initial production, rate of decline and drilling costs of wells drilled and completed across different areas of each play. Existing production is modelled by estimating decline parameters of wells based on latest production information available, and the time when these wells were completed.

Price dynamics affect the number of rigs that are available to drill new wells, with a lag between increases in prices and increases in the number of rigs operating (as observed empirically). Technology increases both the speed at which new wells can be drilled and completed (the number of wells per rig) and the amount of production from each well (the EUR/well). Conversely, the EUR/well of a given area in a given play is assumed to degrade as that area is depleted over time.

Rigs are distributed across plays based on current activity and the expected cost effectiveness of new wells that are drilled. It is assumed that while operators aim to drill only in their most productive areas, some wells are inevitably located in regions with lower EUR/well or higher decline rates. The product of the number of rigs, number of wells per rig, and production per well then gives the new production that comes online in each play in each month starting in January 2020. Results from this module are directly fed into the GEC Model for each of the scenarios implemented. A similar model was developed for shale gas production in the United States.

Box 6.2 ▹ Methodology to account for production decline in oil and gas fields

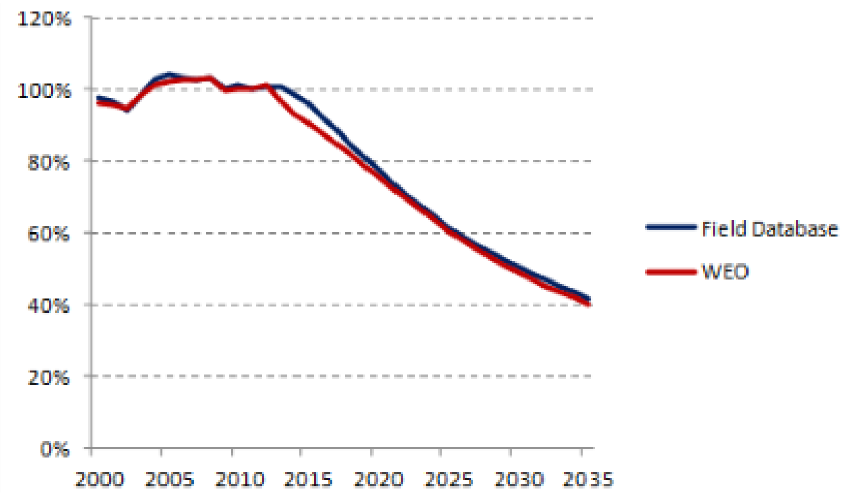
The *World Energy Outlook* has previously presented analyses of decline rates in oil fields on a number of occasions, based on time series of actual production data for a large number of fields. The outcome of this work is a value for observed decline rates by type of field, geographical location and phase of decline, as well as an estimate for the difference between observed decline rates and natural decline rates (i.e. the decline rate that would be observed in the absence of further investment in producing fields).

In principle, this provides the elements to project future production of all fields in decline among the set of fields used. The methodology is as follows:

- For each field in the database, assign a type (e.g. super-giant, giant, onshore, offshore, deepwater) and determine the current decline phase.
- Project future production for each field as per corresponding decline rate provided in *WEO-2013*, updating decline rates as the field changes phase.

But this does not allow the projection of world production from all currently producing fields, as one also needs to project production from fields currently ramping up (i.e. one needs to know their future peak year and peak production) and from declining fields not in the database. This is done using a proprietary commercial database that contains a representation of possible future production for all fields in the world. Based on this more complete data set, the GEC Model oil supply module uses a country-by-country parameterisation of natural decline rates (for each resources type) and a production profile for resources developed in each country during the projection period (i.e. resources developed in a given year then provide a ramping-up of production, followed by peak and decline). As shown in Figure 6.2, this parameterisation gives a good match with the results of the proprietary database (as the two databases have slightly different base productions, both are normalised to allow a clearer comparison of decline) for the long-term decline; in the short term, the IEA field-by-field analysis (coming from the MTOMR) is more conservative than the commercial database, as it accounts for expected field maintenance and weather disruptions.

Figure 6.2 ▷ Evolution of production of currently producing conventional oil fields from a field-by-field database and from the GEC Model



IEA. CC BY 4.0.

Sources: Rystad Energy, IEA analysis and databases.

6.2 Natural gas

Natural gas production and trade projections are derived from a hybrid GEC Model gas supply module involving bottom-up and top-down approaches. The module has similar inputs, logic and functionality to the oil supply module described above. However, contrary to oil, which is assumed to be freely traded globally, gas is assumed to be primarily traded regionally, with inter-regional trade constrained by existing or planned pipelines, LNG plants and long-term contracts. First the top-down module is run for 20 regions (see Annex 1), for which indigenous production is modelled from various factors including remaining technically recoverable resources (Table 6.1), depletion rates, production costs, taxes, prices and various risks in the region. Subtracting domestic production from demand, in aggregate for each importing regional block, yields gas import requirements. For each gas net-exporting regional block, aggregate production is determined by the level of domestic demand and the call on that region's exportable production (which is determined by the import needs of the net importing regions and supply costs). Long-term contracts (current, or assumed for the future) are served first, then exporting regions compete on the basis of marginal production costs plus transport costs, within current and assumed future LNG and pipeline capacities. This provides inter-regional gas trade. The effects of pricing policies (current or assumed for the future) of exporting regions can also be taken into account.

In the bottom-up module, production within each region is allocated to individual countries according to remaining technically recoverable resources, depletion rates and relative supply costs, with a logic similar to that of the oil supply module, but with "demand" being provided by the respective regional production derived from the top-down module.

6.3 Coal

The coal module is a combination of a resources approach (Table 6.1) and an assessment of the development of domestic and international markets, based on the international coal price. Production, imports and exports are based on coal demand projections and historical data, on a country basis. Four markets are considered: coking coal, steam coal, lignite and peat. World coal trade, principally constituted of coking coal and steam coal, is separately modelled for the two markets and balanced on an annual basis.

Table 6.1 ▷ Remaining technically recoverable fossil fuel resources, 2022

Oil (billion barrels)	Proven reserves	Resources	Conventional crude oil	Tight oil	NGLs	EHOB	Kerogen oil
North America	220	2 392	235	215	146	797	1 000
Central and South America	303	854	247	57	49	497	3
Europe	14	111	56	19	28	3	6
Africa	125	451	312	54	83	2	-
Middle East	900	1 122	878	29	171	14	30
Eurasia	146	937	224	85	58	552	18
Asia Pacific	51	275	120	72	64	3	16
World	**1 760**	**6 142**	**2 071**	**531**	**600**	**1 868**	**1 073**

Natural gas (trillion cubic metres)	Proven reserves	Resources	Conventional gas	Tight gas	Shale gas	Coalbed methane
North America	17	147	50	10	81	7
Central and South America	9	84	28	15	41	-
Europe	5	46	18	5	18	5
Africa	19	101	51	10	40	0
Middle East	83	121	101	9	11	-
Eurasia	69	167	129	10	10	17
Asia Pacific	21	138	44	21	53	20
World	**222**	**803**	**421**	**80**	**253**	**49**

Coal (billion tonnes)	Proven reserves	Resources	Coking coal	Steam coal	Lignite
North America	257	8 389	1 119	5 751	1 519
Central and South America	14	60	3	32	25
Europe	137	982	164	414	403
Africa	15	343	46	296	-
Middle East	1	41	36	5	-
Eurasia	191	2 015	386	997	632
Asia Pacific	460	8 974	1 736	5 810	1 428
World	**1 074**	**20 804**	**3 490**	**13 306**	**4 007**

Notes: NGLs = natural gas liquids; EHOB = extra-heavy oil and bitumen. The breakdown of coal resources by type is an IEA estimate. Coal world resources exclude Antarctica.

Sources: BGR, 2021; BP, 2022; CEDIGAZ, 2023; OGJ, 2022; US DOE/EIA, 2022; USGS, 2012a; USGS, 2012b; IEA databases and analysis.

6.4 Bioenergy

Bioenergy is an important renewable energy option in all its forms: solid (biomass), liquid (biofuels) and gas (biogas and biomethane). Bioenergy provides a significant portion of renewables-based electricity, heat, and transport fuels in all scenarios of the GEC Model and – as biomethane – it can also contribute to decarbonising the gas network. Many regions or countries have or are considering policies that will increase the demand for bioenergy in the power and transport sectors further in the future.

The Bioenergy supply module is designed to assess the ability of GEC Model regions to meet their demand for bioenergy for power generation, biofuels and biogases with domestic resources. Where they are not able to do so, the module also simulates the international trade of liquid biofuels. The availability of bioenergy is restricted to renewable sources of biomass feedstock that is not in competition with food and feed. The bioenergy supply determines primary bioenergy availability, which – for liquid and gaseous uses – feeds into the liquid biofuels and biogas and biomethane supply modules for transformation prior to final use (see Section 5.4).

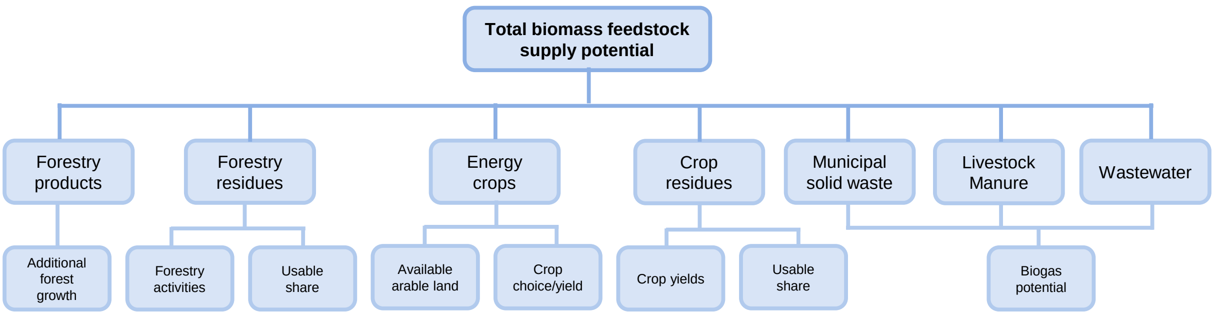
Bioenergy supply module

Biomass supply potentials by region

The feedstock supply potentials are built on a wide range of data related to land, crops and food demand, originating largely from the database of FAO, as well as academic literature and the Global Agro-Ecological Zones (GAEZ) system, a collaborative project involving FAO and IIASA.

Total supply potentials by region in the bioenergy supply module are the sum of the potential supply for four categories of feedstocks: forestry products, forestry residues, agricultural residues and energy crops (Figure 6.3). Starting from current activity levels, ramping up collection and delivery of these often diffuse feedstocks requires significant lead times before maximum potential supply levels can be reached. The potential supply of forestry and agricultural residues is reduced by industrial and residential use to produce heat, as well as demand for traditional uses of bioenergy.

Figure 6.3 ▷ Schematic of biomass supply potentials



Note: Only the organic fraction of municipal solid waste is included in the biomass supply.

Forestry products include only forestry activities, such as harvesting trees and complementary fellings, for the primary purpose of producing power or transport biofuels. The maximum potential availability of forestry products is limited to the expected growth in total forest area per year, after other forestry demands are met, in each region, thereby avoiding direct deforestation.

Forestry residues are those materials, or secondary products, produced from forestry activities where the primary motivation is something other than to produce bioenergy. These include forestry scraps, bark leftover from the timber industry, industrial by-products, waste wood and sawdust leftover after wood processing. The maximum potential availability is limited by the level of the related activities and the usable share of the leftover materials.

Crop residues are the leftover materials after harvesting crops, such as corn stover, straw and bagasse from sugarcane processing. Data for harvests by region include the following crops: barley, maize (corn), oats, rice, sorghum, wheat, other cereals, rapeseed, soybeans, sunflower seed and sugarcane. The maximum potential availability is limited by the amount of crops harvested and by the recoverable share of the residues. It is important for a portion of the residues to remain in fields to replenish soil nutrients and maintain yields for future harvests, by helping reduce soil erosion and maintaining water and temperature in the soils. The percentage of these residues that can be made available for energy production in a sustainable manner is region- and crop-specific, and is still being investigated actively.

Other waste and residue sources modelled are livestock manure, the organic fraction of municipal solid waste (MSW) and wastewater for biogas production. Livestock manure includes cattle, poultry, pig and sheep. Similarly to crop residues, these feedstock potentials are built on a wide range of data originating largely from the FAO database and OECD-FAO study (OECD/FAO, 2018) for pigs, poultry and sheep. The organic fraction of municipal solid waste includes food and green waste, paper and cardboard, and wood, and is calculated from a World Bank study (World Bank, 2018). Wastewater includes only municipal wastewater and is based on the output data from the Water module previously developed by the World Energy Outlook team. These biomass potentials are included in the model as biogas potential.

Energy crops are those grown specifically for energy purposes, including food sugar and starch feedstock for ethanol (e.g. corn, sugarcane, and sugar beet), vegetable oil feedstock for bio-based diesels (e.g. rapeseed, soybean and oil palm fruit) and lignocellulosic material (e.g. switchgrass, poplar and miscanthus) for advanced biofuels. The maximum potential availability is determined by the available arable land, after taking into account food-related demand for land, crop choice and rising yields over time.

The potential supply from energy crops (million tonnes) is calculated as follows:

$$P_{t,r} = \sum_{l,g,c} \left(x_{t,r,l,g,c} \times y_{t,r,l,g,c} \times s_{t,r,c} \right)$$

where, for a given year *t* and region *r,*

- $P_{t,r}$ is the potential biomass feedstock supply from energy crops;
- $x_{t,r,l,g,c}$ is the available land by type *l*, grade *g*, and crop *c;*
- $y_{t,r,l,g,c}$ is the crop yield; and
- $s_{t,r,c}$ is the share of available land for each crop.

Available land is divided into three grades of land quality (prime, good and marginal) and three types of land (cultivated, unprotected grassland and unprotected forest land). Lower quality grades of land provide lower crop yields. In this assessment, unprotected forest land is not allowed to be converted to crop lands and so is unavailable for bioenergy purposes. Crop yields are defined by region, reflecting the average growing conditions in a region, and are assumed to continue to improve moderately through 2035. Crop choice is influenced by currently favoured crops for bioenergy, the changing economics of feedstock (through increased yields and relative attractiveness compared to the fossil fuel alternative), and policy development. For example, policy goals for advanced biofuels will increase demand for lignocellulosic energy crops, decreasing the share of land devoted to conventional feedstock.

Supply to meet demand

Demand for biomass feedstock is based on demand projections for power, industry, buildings and transport sectors. To meet demand, domestic supplies are given priority; the remainder is covered through international markets for modelled bioenergy trade flows, namely liquid biofuels. The model is calibrated to meet existing trade flows as assessed by the IEA's *Renewable Energy Market* reports.

Domestic supply

Biomass feedstock competes to meet demand on the basis of conversion costs, including feedstock prices and the energy contents of feedstock. Several biomass feedstock types can be used for both power generation and the production of liquid biofuels and biogases. These include forestry products, forestry residues and agricultural residues. Where this is the case, the net present values for both uses are compared and ranked, based on technology cost data from the GEC Model and IEA's Mobility Model. According to rank, available biomass feedstock supplies are allocated. Domestic supply of liquid biofuels is limited by refining capacity. In the near term, this is restricted by existing refineries and those already under construction or planned.

Global trade

The model uses a global trade matrix to match unsatisfied demand with available supply on a least-cost basis, including transportation costs. Transportation costs between regions include both average over-land and by-sea costs. Four products are traded: ethanol, biodiesel, biojet kerosene and biomethanol. These liquid biofuels are high-density uniform products that can be made from residues and other feedstock, and their uniformity and density make handling and transportation easier and less expensive over long distances compared with other bioenergy resources. The conversion of biomass feedstock to liquid biofuels occurs in the exporting region, therefore conversion costs are calculated based on the technology costs in the exporting region. Importing regions choose suppliers based on least-cost available supplies (including transportation costs). Exporting regions make supplies available to importing regions willing to pay the highest price.

Collaboration

IEA bioenergy demand and supply 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, particularly on biomass feedstock supply, land use and emissions from the agriculture, forestry and other land use (AFOLU) sectors.

Critical minerals

Scope

The critical minerals model, added as a permanent module in the GEC Model during the 2022 modelling cycle, assesses the mineral requirements for the following clean energy technologies:

- solar PV (utility-scale and distributed)
- wind (onshore and offshore)
- concentrating solar power (parabolic troughs and central tower)
- hydropower
- geothermal
- bioenergy for power
- nuclear power
- electricity networks (transmission, distribution, and transformer)
- electric vehicles (battery electric and plug-in hybrid electric vehicles)
- battery storage (utility-scale and residential)
- hydrogen (electrolysers and fuel cells).

All of these energy technologies require metals and alloys, which are produced by processing mineral-containing ores. Ores – the raw, economically viable rocks that are mined – are beneficiated to liberate and concentrate the minerals of interest. Those minerals are further processed to extract the metals or alloys of interest. Processed metals and alloys are then used in end-use applications. While this analysis covers the entire mineral and metal value chain from mining to processing operations, we use "minerals" as a representative term for the sake of simplicity.

We focus specifically on the use of minerals in clean energy technologies, given that they generally require considerably more minerals than their fossil fuel counterparts. Our model also focuses on the requirements for building a plant (or making equipment) and not on operational requirements (e.g. uranium consumption in nuclear plants).

Our model considers a wide range of minerals used in clean energy technologies listed in Table 7.1. They include chromium, copper, major battery metals (lithium, nickel, cobalt, manganese and graphite), molybdenum, platinum group metals, zinc, rare earth elements, silicon, silver and others.

Table 7.1 ▹ Critical minerals in scope

Focus minerals	Other minerals			
• Cobalt	• Arsenic	• Hafnium	• Niobium	• Tin
• Copper	• Boron	• Indium	• Platinum	• Titanium
• Lithium	• Cadmium	• Iridium	• Selenium	• Tungsten
• Nickel	• Chromium	• Lead	• Silicon	• Vanadium
• Rare earth elements (Neodymium, Dysprosium, Praseodymium, Terbium, others)	• Gallium	• Magnesium	• Silver	• Zinc
	• Germanium	• Manganese	• Tantalum	
	• Graphite	• Molybdenum	• Tellurium	

Steel and aluminium are widely used across many clean energy technologies, but we have excluded them from the scope of this analysis. Steel does not have substantial security implications and the energy sector is not a major driver of growth in steel demand. Aluminium demand is assessed for electricity networks only as the outlook for copper is inherently linked with aluminium use in grid lines, but is not included in the aggregate demand projections.

7.1 Demand

In 2023, the IEA published the interactive Critical Minerals Data Explorer on its website. This online tool provides global demand projections for 37 critical minerals needed for clean energy transitions across the three main IEA scenarios and 12 technology-specific cases.

For each of the clean energy technologies, we estimate overall mineral demand using four main variables:

- clean energy deployment trends under different scenarios
- sub-technology shares within each technology area based on technology-specific cases
- mineral intensity of each sub-technology
- mineral intensity improvements.

Clean energy deployment trends under the Stated Policies Scenario (STEPS), the Announced Pledges Scenario (APS), and the Net Zero Emissions by 2050 Scenario (NZE Scenario) are taken from the projections from the 2023 modelling cycle.

Sub-technology shares within each technology area (e.g. solar PV module types or EV battery chemistries) are taken from the 2023 GEC Modelling Cycle, complemented by the Global EV Outlook 2023 and other sources.

Mineral intensity assumptions were developed through extensive literature review (see IEA [2021] for details) and expert and industry consultations, including with IEA Technology Collaboration Programmes.

The pace of mineral intensity improvements varies by scenario, with the STEPS generally seeing minimal improvement over time as compared to modest improvement (around 10% in the longer term) assumed in the APS and NZE. In areas that may particularly benefit from economies of scale or technology improvement (e.g. silicon and silver use in solar PV, platinum loading in fuel cells, rare earth elements use in wind turbines), specific improvement rates have been applied based on the review of underlying drivers.

7.2 Supply requirements

For the five focus minerals (cobalt, copper, lithium, nickel and rare earth elements), total demand and primary supply requirements have been assessed. Consumption outside the clean energy sector has been estimated using historical consumption by end-use applications, relevant activity drivers (e.g. GDP, industry value added, steel production, etc.) and material intensities. Primary supply requirements have been assessed by deducing projected secondary supply from projected total demand.

Secondary production is estimated with two parameters: the average recycling rate and the lifetime of each end-use sector. The recycling rate is the combination of the end-of-life collection rate (the amount of a certain product being collected for recycling) and the yield rate (the amount of material a recycling process can actually recover). For existing waste streams (e.g. industrial applications), we assume only marginal improvement in collection rates, while for emerging technologies such as lithium-ion batteries, we assume collection rates increase at a faster pace. For batteries, the collection rates gradually increase from around 45% in the early-2020s to 80% by 2040. For batteries, the yield rate is assumed to vary according to the technical limitations for the extraction of each mineral using the currently available recycling methods. The reuse rates are much lower than the collection rate for recycling as the use of second-life batteries faces many technical and regulatory obstacles.

Emissions

8.1 CO_2 emissions

As energy-related CO_2 emissions account for the lion's share of global greenhouse gas emissions, one of the important outputs of the GEC Model is region-by-region CO_2 emissions from fuel combustion and from industrial processes. Carbon dioxide emissions from fuel combustion and from industrial processes do not include fugitive emissions from fuels, flaring or CO_2 from transport and storage. Unless otherwise stated, CO_2 emissions reported from the GEC Model refer to combustion of fossil fuels and non-renewable waste, industrial process CO_2 emissions, and fugitive emissions from flaring. GEC Model CO_2 emissions accounting also consider carbon dioxide removal from the atmosphere through capturing CO_2 from the air (through direct air capture [DAC]) or from biogenic sources (Bioenergy with carbon, capture, and storage [BECCS]) for permanent storage in underground reservoirs.

For each GEC Model region, sector and fuel, CO_2 emissions from fuel combustion are calculated by multiplying energy demand by an implied CO_2 content factor. The implied CO_2 content factors for coal, oil and gas differ between sectors and regions, reflecting the product mix and efficiency. They have been calculated as an average of the past three years from IEA energy-related sectoral approach CO_2 data for all GEC Model regions and are assumed to remain constant over the projection period.

Process-related CO_2 emissions from various industrial sources are estimated by GEC Model region. For the estimation a Tier 1 or Tier 2 method has been used, which in general means that emissions have been estimated based on the production of industrial materials and an emissions factor based on the 2006 Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories. So far the analysis is limited to the most important sources of industrial process emissions:

- Mineral industry: clinker, lime, limestone use, soda ash use
- Metal industry: primary aluminium
- Chemical industry: ammonia, methanol, ethylene, soda ash
- Non-energy products: lubricants and paraffin
- Transformation: coal-to-liquids, coal-to-gas and gas-to-liquids, hydrogen production, biofuels production (which can bring Carbon Dioxide Removal).

The GEC Model also accounts for carbon capture, utilisation and storage (CCUS). CCUS technologies can be deployed in the electricity and heat, industry and transformation sectors. In the model, captured CO_2 emissions can be stored in underground geological formations, onshore or offshore or used as a feedstock in manufacturing of synthetic fuels in particular.

CO_2 emissions from land use, land-use change and forestry (LULUCF) consistent with current policy settings (for the STEPS) and announced pledges (for the APS), as well as bioenergy demand in IEA scenarios have been assessed by IIASA using the GLOBIOM model (IIASA, 2022).

8.2 Methane emissions

The Global Methane Tracker within the *GEC Model* framework is used to produce IEA estimates for methane emissions from the supply or use of fossil fuels (coal, oil and natural gas) and from the use of bioenergy (such as solid bioenergy, liquid biofuels and biogases). The methodology for the main segments of methane emissions is as follows:

- **Upstream and downstream oil and gas** - Our approach to estimating methane emissions from global oil and gas operations relies on generating country-specific and production type-specific emission intensities that are applied to production and consumption data on a country-by-country basis.

- **Coal mine methane** - Estimates for coal mine methane (CMM) emissions are derived from mine-specific emissions intensities for three major coal producing countries. The mine-level CMM estimates generated in this way are then aggregated and verified against country-level estimates taken from satellite-based measurements. Based on these data, coal quality (e.g. the ash content or fixed carbon content of coal produced by individual mines), mine depth and regulatory oversight are used as key factors to estimate CMM emission intensities for mines in other countries for which there are no reliable direct estimates.

Emissions from fuel combustion (end use) - Estimates for methane emissions from the use of fuels (including bioenergy) in stationary and mobile applications are from the IEA Greenhouse Gas Emissions from Energy. The Tier 1 methodology from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories have been adopted for the purpose of estimating the non-CO_2 emissions from fuel combustion. For more information on the methodology used to develop estimates for methane emissions from the supply or use of energy, please refer to the Global Methane Tracker Documentation.

8.3 Other non-CO_2 greenhouse gas emissions

Most energy-related greenhouse gas (GHG) emissions, both CO_2 and non-CO_2, in IEA scenarios are modelled using the IEA's GEC Model. Significant sources of other GHGs, e.g. black carbon, as well as GHGs related to land use and agriculture consistent with IEA scenarios, such as biogenic methane, are modelled by the IIASA using the GAINS model (IIASA, 2023) and the GLOBIOM model.

Projections for all remaining types and sources of GHG emissions, such as F-gases used mainly in industrial applications, are supplemented using the scenario database published as part of the IPCC Special Report on Global Warming of 1.5 °C (IPCC, 2018)

8.4 Air pollution

Emissions of major air pollutants resulting from the GEC Model energy scenarios have been estimated in co-operation with IIASA. Using the IIASA GAINS model, estimates have been made for the following local air pollutants: sulphur dioxide (SO_2), nitrogen oxides (NO_x), black carbon and $PM_{2.5}$.[1] More information can be found in the WEO Special Report on *Energy and Air Pollution*[2] as well as in a previous detailed report outlining the approach, results and information about health impacts, as well as pollution control costs.

8.5 Global temperature impacts

The average global surface temperature rise that would result from GHG and aerosol emissions in GEC Model scenarios has been carried out in close co-operation with Climate Resource Pty Ltd using the *Model for the Assessment of Greenhouse Gas Induced Climate Change* ("MAGICC"),[3] and drawing on other tools used by the global scientific community. The MAGICC climate models have been used extensively in assessment reports written by the IPCC. MAGICC7, the version used in this analysis, is used in the IPCC's Sixth Assessment Report (IPCC, 2021) and described in Cross-Chapter Box 7.1 therein.

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[1] Fine particulate matter is particulate matter that is 2.5 micrometres in diameter and less; it is also known as $PM_{2.5}$ or respirable particles because they penetrate the respiratory system further than larger particles.

[2] https://www.iea.org/reports/energy-and-air-pollution

[3] Information sourced to Climate Resource in *WEO-2021* was contributed by Climate Resource Pty Ltd using MAGICC7. Neither Climate Resource nor any of its officers, employees, contractors or affiliates make any warranty or guarantee about the accuracy, completeness or reliability of the climate data provided and any liability resulting from its use is the sole responsibility of the reader.

Energy and CO_2 decomposition

The GEC Model includes a module – the decomposition module – used to quantify the difference of energy and CO_2 emissions between two scenarios or in one scenario over time. Decomposition analysis is applied to all end-use sectors (industry, transport, buildings and agriculture) and the transformation sectors (electricity generation and heat production, refineries, biofuels, hydrogen and hydrogen-based fuels, other energy sectors) ex-post to the GEC Model using the final results for the scenarios being analysed.

The difference between scenarios or points in time is apportioned to several "levers" that represent important mitigation measures to reduce energy consumption and emissions within the energy system. These include:

- **Activity:** difference in energy or emissions from economic activity and change in service demand, e.g. increase in industrial value added, travelled kilometres or used floor space.
- **Avoided demand – resource efficiency:** difference in energy or emissions from efficiency improvements in the use of resources, e.g. extension of building lifetimes leading to less steel or cement demand.
- **Avoided demand – behaviour:** difference in energy or emissions from avoided demand due to behavioural shifts. Please see the behavioural change sections in the Energy demand section (Section 3) for more details.
- **Climate effect:** difference in energy or emissions in the buildings sector caused by climate change impacts on temperature changes. IPCC scenario temperature projections are used to determine the shifted energy use.
- **Energy efficiency:** difference in energy or emissions from technical efficiency improvements of deployed technologies. Examples include improved insulation of buildings, the deployment of appliances with higher efficiency standards, improved fuel economy or more efficient motors.
- **Fuel shifts:** difference in energy or emissions from changing the fuel used, including through using different technologies that may have higher efficiency, e.g. the shift to electric vehicles from combustion engines or the shift to heat pumps from gas boilers. This effect is further broken down to specific fuels:
  - **Electrification:** assessing the changes for electricity, e.g. use of electric vehicles or direct electrification in industry including efficiency gains. For emissions, this can be done in a direct decomposition (excluding emissions from the electricity and heat sector) or in an indirect decomposition (including emissions from the electricity and heat sector).
  - **Bioenergy:** assessing the changes for bioenergy, e.g. in power generation or as a fuel in buildings, transport or industry.
  - **Other renewables:** assessing the changes for other renewables, e.g. use of solar PV and wind for power generation or solar thermal in buildings.
  - **Hydrogen:** assessing the changes for the use of hydrogen and hydrogen-based fuels, e.g. in the transport sector or in energy-intensive industries. On-site hydrogen use, such as electrolytic hydrogen-based steel or ammonia production, are also accounted to this lever.
  - **Other fuel shifts:** assessing the changes for other fuels, e.g. switches between fossil fuels or nuclear.
- **CCUS:** difference in energy or emissions from the deployment of carbon capture utilisation and storage.

The decomposition module also has the capability to apportion emission and energy changes according to technology maturity category, using the technology readiness level (TRL) of each modelled technology or strategy. The TRL assessment is based on the ETP Clean Energy Technology Guide and classifies the technologies being deployed in a given year in 4 tiers based on their current TRL status: as mature, at market uptake, under demonstration or still a prototype. The TRL breakdown makes it possible to allocate the contribution of levers such as fuel switching or energy efficiency to different technological maturities, and thus to highlight where there is need for further progress in innovation to close the gap between scenarios or over time within a scenario. Only savings from behavioural measures are not allocated to a TRL since these are not primarily driven by the technologies deployed but by shifted behaviour of end-users.

The decomposition module adheres to the Logarithmic-Mean-Divisia-Index (LMDI) approach to break down the difference between a reference and a comparison point (either another scenario or the previous year) for a given year by the key levers (Ang, 2004). The approach is based on the Kaya equation that singles out different effects and separates the evaluated levers. The Kaya equation can vary by sector but can be described as an example for CO_2 emissions with the activity (A) and the energy (E) for each technology (t) as follows:

$$CO_{2_t} = A * \frac{A_t}{A} * \frac{E}{A_t} * \frac{CO_2}{E}$$

In this equation, the multipliers represent the activity (A), structural changes (S), energy intensity (I) and the CO_2 intensity (C). These multipliers can be processed and further broken down to calculate all the above-mentioned key levers that are assessed.

Applying the LMDI function to the difference between a reference (ref) and a comparison point (comp), leads to the following difference for emissions between these scenarios:

$$CO_{2_{t,comp}} - CO_{2_{t,ref}} = \omega_t * \left\{ \ln\left(\frac{A_{comp}}{A_{ref}}\right) + \ln\left(\frac{S_{comp}}{S_{ref}}\right) + \ln\left(\frac{I_{comp}}{I_{ref}}\right) + \ln\left(\frac{C_{comp}}{C_{ref}}\right) \right\},$$

with

$$\omega_t = \frac{CO_{2_{t,comp}} - CO_{2_{t,ref}}}{\ln CO_{2_{t,comp}} - \ln CO_{2_{t,ref}}}$$

These formulas are defined in a similar way for an energy decomposition. For a decomposition between scenarios, the two scenarios, comparison and reference, are the compared points, e.g. the NZE Scenario and the STEPS. For a decomposition of one scenario over time, the comparison and reference points use the same GEC Model scenario but just with a delay of one year between (e.g. comparing values in "t" with values in "t-1" as a reference) to calculate the levers for each year step. For the calculation of effects in a target year, annual effects are accumulated for the period after the base year.

The decomposition module calculates the effects considering high technological resolution, which means by end-use technology and fuel for each modelled region. This framework makes it possible to calculate interlinkages between effects, such as the indirect or direct decomposition reflecting emissions from power generation or energy efficiency improvements from fuel switching, e.g. electrification. Results at the sectoral, regional or global level are obtained by summing relevant contributions.

Investment

10.1 Investment in fuel supply and the power sector

Investment is measured as the ongoing capital expenditures in fuel production and power generation capacity, as well as infrastructure. Projections of investment requirements by scenario are derived from the GEC Model energy supply and demand modules.

The calculation of the investment requirements for power generation and fuel supply involved the following steps for each region:

- New capacity needs for production, transportation and (where appropriate) transformation were calculated on the basis of projected demand trends, future supply required, estimated rates of retirement of the existing supply infrastructure and decline rates for oil and gas production.
- Unit capital cost estimates were compiled for each component in the supply chain. These costs were then adjusted for each year of the projection period using projected rates of change based on a detailed analysis of the potential for technology-driven cost reductions and on country-specific factors.
- Incremental capacity needs were multiplied by unit costs to yield the amount of investment needed as if the assets were constructed and became operational on an overnight basis.
- Finally, using technology and country/region-specific spending profiles, overnight investment needs were then distributed uniformly across construction lead times estimated for each asset, which we refer to as 'investment spending'.

The estimates of investment in the current decade take account of projects that have already been decided and expenditures that are already ongoing. This approach based on capital spending can differ across supply areas. For some sectors, such as power generation, the investment is spread out from the year in which a new plant or upgrade of an existing one begins its construction to the year in which it becomes operational. For other sources, such as upstream oil and gas and liquefied natural gas (LNG) projects, investment reflects the capital spending profiles typically incurred as production from a new source ramps up or to maintain output from an existing asset.

For the purposes of outlooks using the GEC Model, investment is defined as capital expenditure only. It does not include spending that is usually classified as operations, maintenance, or spending devoted to servicing financing costs.

Short-term oil and natural gas upstream investment

Projections of upstream investment are based on a combination of bottom-up and top-down approaches. The former involves a detailed analysis of the plans and prospects for oil and gas industry investment in the future, with the aim of determining how much the industry is planning to invest in response to current prices and to the need for new capacity and of assessing the resulting additions to production capacity.

This analysis is based on a survey of the capital-spending programmes of over 80 leading upstream oil and gas companies (national and international companies and pure exploration and production companies), covering actual capital spending from 2000 to 2022 and their plans or forecasts of upcoming spending when available. Companies were selected on the basis of their size as measured by their production and reserves, though geographical spread and data availability also played a role. The surveyed companies account for over three-quarters of world oil and gas production. Total industry investment was calculated by adjusting upwards the spending of the companies, according to their share of world oil and gas production for each year. Data was obtained from companies' annual and financial reports, corporate presentations, press reports, trade publications and direct contacts in the industry.

Table 10.1 ▷ Sub-sectors and assets included in fuel supply investment

Sub-sector	Assets
Oil and gas	• Upstream oil • Upstream gas • Midstream oil (pipelines) • Midstream gas (pipelines and LNG) • Refining (greenfield) • Refining (upgrade and maintenance)
Coal supply	• Coal mining • Coal transportation
Low-emissions fuels	• Biogases • Liquid biofuels • Hydrogen and hydrogen-based fuels production • Hydrogen infrastructure

Note: LNG = liquefied natural gas.

Long-term investment in fuel supply

Projections of long-term oil, gas, coal and low-emissions fuels investment requirements are generated in the respective supply-side modules. The level of investment is set to meet the level of demand projected in a given country, region and year. The methodology establishes a direct link over time between new production capacity brought on stream, the cash flow generated and the investments required. The cost of new capacity is estimated from a set of variables: size of the reserves, degree of depletion, location type of resource, technology employed, technology learning, and underlying assumptions for cost changes (which are a function of oil prices in the oil and gas supply-side modules). A more detailed projection was made for investments associated with hydrogen-based supply, including production of low-carbon hydrogen from electrolysis, fossil fuels (fitted with carbon capture utilisation and storage [CCUS]) and infrastructure.

Power sector investment

Large investments in the power sector will be needed over the Outlook period to meet rising electricity demand, achieve decarbonisation goals and to replace or refurbish obsolete generating assets and network infrastructure. The overnight investments in generating assets are a straightforward calculation multiplying the capital cost (USD/kW) for each generating technology by the corresponding capacity additions or replacement/ refurbishment for each modelled region/country. Investment outlays are then spread over time based on spending profiles that begin at the start of construction or financial close and finish when an asset becomes operational.

The capital costs assumed in the power generation sector are based on a review of the latest country data available and on assumptions of their evolution over the projection period. They represent overnight costs for all technologies. For renewable sources and for plants fitted with CCUS facilities, the projected investment costs result from the various levels of deployment in the different scenarios. Indicative overnight costs and other relevant investment assumptions for all technologies by region may be found on the GEC Model key input data page.

Table 10.2 ▷ Sub-sectors and assets included in power sector investment

Sub-sector	Assets
Fossil-fuel based power generation	• Coal-fired power • Coal-fired power with CCUS • Gas-fired power • Gas-fired power with CCUS • Oil-fired power
Nuclear power generation	• Nuclear power plants (greenfield) • Refurbishments and upgrades for long-term operations
Renewable power generation	• Bioenergy • Hydropower • Wind (onshore and offshore) • Geothermal • Solar PV (utility-scale; residential, commercial and other distributed) • Solar thermal • Marine
Electricity grids	• Transmission • Distribution • Public EV chargers
Battery storage	• Utility-scale and buildings

Note: CCUS = carbon capture, utilisation and storage; PV = photovoltaic; EV = electric vehicle.

10.2 Demand-side investments

Demand-side investments are consumer outlays for the purchase of end-use equipment. Ongoing spending associated is assumed to occur in the same year as when assets become operational. For efficiency, this does not include all of the spending, only the amount that is spent (including taxes and freight costs) to procure equipment that is more efficient than a baseline. The investment cost includes labour costs that are directly related to an installation, while additional costs can arise from administrative procedures, legal protection and border clearances, which are also included in the cost estimate. In other words, this calculation reflects the additional amount that consumers have to pay for higher energy efficiency over the projection period.

Across the GEC Model regions and for each end-use sector (industry, transport and buildings), the investment needed to move to greater efficiency levels have been analysed. The analysis is based on investment cost, stock turnover and the economic return required across sub-sectors in industry, across modes of transport and across end-uses in buildings. For example, in the road transport sector, the costs of efficiency improvements and of a switch to alternative fuel vehicles are used as an input to the model to determine each option's cost-competitiveness. Based on the outcome of this analysis, the investment needs are then determined by multiplying the number of vehicles sold in each year by the costs of each vehicle.

In addition to energy efficiency, end-use investments include direct use of renewables, electric vehicles, electrification in buildings/industry, use of hydrogen and hydrogen-based fuels, and CCUS in industry.

Demand model outputs include the additional annual capital needs for each region and end-use sector. The impact of the energy savings on consumers' bills is also analysed. The sectoral end-user prices (including taxes) have been used to assess the overall impact of the policies on consumers over time. The results also include the impact on main importing countries.

Table 10.3 ▷ Sub-sectors and assets included in end-use energy investment

Sector	Sub-sector
Buildings	• Energy efficiency (including building envelopes and retrofits) • Electrification • Renewables for end use • Hydrogen-based use
Industry	• Energy efficiency • Electrification • Renewables for end use • CCUS • Hydrogen-based use • Fossil fuel-based industrial facilities
Transport	• Energy efficiency of road transport • Electrification of road transport and international marine transport • Hydrogen and hydrogen-based road transport and shipping

10.3 Financing for investments

Sources of finance

Building upon analysis carried out in 2021 and the Financing Clean Energy Transitions in Emerging and Developing Economies report, an updated assessment of the sources of finance associated with investments was carried out. While project developers act as the primary actors investing in energy assets, their success depends on a having robust inter-connected system of financial sources and intermediaries, diverse investment vehicles to facilitate flows and clear signals for action, based on profit expectations and risk profiles.

The sources of finance are characterised across four broad parameters:

- type of financing structure (off-balance sheet [project finance] or on-balance sheet [corporate finance])
- type of provider (private or public [public finance institutions and state-owned enterprises])
- type of instrument (according to capital structure - debt or equity)
- origin of provider (international or domestic sources).

For further details on estimation approach, please see the *World Energy Investment 2022* Methodology Annex.

Cost of finance

The GEC Model incorporates differentiated assumptions on the cost of capital across regions within the supply, power and end-use sectors. For example, as some countries pursue efforts to minimise emissions from oil and gas operations in the Announced Pledges Scenario (APS), this increases their production costs relative to other producers and in many cases also involves additional financing costs (compared to those assumed in the Stated Policies Scenario [STEPS]). As explained in Section 4, a detailed analysis has been undertaken to reflect the reduction in financing costs for solar PV and wind across GEC Model countries/regions. Investment decisions in energy efficiency reflect the estimates for the prevailing debt and equity finance costs faced by consumers (for residential buildings and vehicles), businesses in the real estate sector (for commercial buildings) and companies from different industrial sectors across GEC Model regions. Financing costs are expressed in pre-tax terms calculated using the weighted average cost of capital (WACC):

$$WACC_{real,pre-tax} = \frac{1 + (C_e \times w_e + C_d \times w_d)}{1 + inflation} - 1$$

Where:

C_e	Cost of equity
C_d	Cost of debt
w_i	share of debt or equity in the capital structure

For sectors where prices and underlying contracts are largely denominated in international currencies (e.g. USD), as in the oil and gas industry, cost components were estimated using mature market risk-free rates adjusted for country and sectoral risks. For sectors where prices and underlying contracts are denominated in local currencies, such as in power and end-use, cost components were estimated using local market risk-free rates adjusted for country and sectoral risks. Nominal data are converted into real terms using the Fischer Equation. Estimating the WACC components for the different energy sectors reflects data from financial markets and academic literature, complemented by interviews with market experts and practitioners. In addition, differentiated WACCs for the power sector outlook include analysis of auction results and power purchase agreement (PPA) pricing.

$$CO_{2_t} = A * \frac{A_t}{A} * \frac{E}{A_t} * \frac{CO_2}{E} CO_{2_{t,comp}} - CO_{2_{t,ref}} =* \left\{\ln\left(\frac{A_{comp}}{A_{ref}}\right) + \ln\left(\frac{S_{comp}}{S_{ref}}\right) + \ln\left(\frac{I_{comp}}{I_{ref}}\right) + \ln\left(\frac{C_{comp}}{C_{ref}}\right)\right\},$$
$$= \frac{CO_{2_{t,comp}} - CO_{2_{t,ref}}}{\ln CO_{2_{t,comp}} - \ln CO_{2_{t,ref}}}$$

Energy access

11.1 Definition of modern energy access

There is no single internationally accepted and internationally adopted definition of modern energy access. Yet significant commonality exists across definitions, including:

- Household access to a minimum level of electricity
- Household access to safer and more sustainable (i.e. minimum harmful effects on health and the environment as possible) cooking and heating fuels and stoves
- Access to modern energy that enables productive economic activity, e.g. mechanical power for agriculture, textile and other industries
- Access to modern energy for public services, e.g. electricity for health facilities, schools and street lighting

All these elements are crucial to economic and social development, as are a number of related issues that are sometimes referred to collectively as "quality of supply", such as technical availability, adequacy, reliability, convenience, safety and affordability.

The data and projections from the GEC Model focus on two elements of energy access: households having access to a minimum level of electricity and to clean cooking facilities. The IEA defines energy access as "*a household having reliable and affordable access to both clean cooking facilities and to electricity, which is enough to supply a basic bundle of energy services initially, and with the level of service capable of growing over time*". This definition of energy access serves as a benchmark to measure progress towards goal SDG 7.1 and as a metric for our forward-looking analysis.

Access to electricity entails a household having initial access to sufficient electricity to power a basic bundle of energy services – at the minimum, several lightbulbs, phone charging, a radio and potentially a fan or television – with the level of service capable of growing over time. In our projections, the average household who has gained access will have in time enough electricity to power four lightbulbs operating at five hours per day, one refrigerator, a fan operating six hours per day, a mobile phone charger and a television operating four hours per day, which equates to an annual electricity consumption of 1 250 kWh per household with standard appliances, and 420 kWh with efficient appliances. This service-level definition cannot be applied to the measurement of actual data simply because the level of data required does not exist in a large number of cases. As a result, our electricity access databases focus on a simpler binary measure of those that have a connection to an electricity grid, or have a renewable off- or mini-grid connection of sufficient capacity to deliver the minimum bundle of energy services mentioned above. For example, in the case of Solar off-grid, only Solar Home Systems of capacity above 10 Wp are included in access rates. See the IEA “Guidebook for Improved Electricity Access Statistics” for more definitions.

Access to clean cooking facilities means access to (and primary use of) modern fuels and technologies, including natural gas, LPG, electricity and biogas, or improved biomass cookstoves (ICS) of ISO Tier >2 that have considerably lower emissions and higher efficiencies than traditional three-stone fires for cooking. Currently, very few ICS models attain this lower emissions target, particularly under real-world cooking conditions. Therefore, our clean cooking access historic database refers to households that rely primarily on fuels other than biomass (such as fuelwood, charcoal, tree leaves, crop residues and animal dung), coal or kerosene for cooking. For our projections, only the most improved biomass cookstoves that deliver significant improvements are considered as contributing to energy access. The main sources for the historic data are the World Health Organisation (WHO) Household Energy Database and the IEA Energy Balances.

11.2 Outlook for modern energy access

Outlook for electricity access

The IEA's electricity access database[1] provides valuable information about the current electrification rates in a large number of countries. In order to provide an outlook for electricity access in the next decades, a model able to generate projections of electrification rates by region has been developed. The projections are based on an econometric panel model that regresses historic electrification rates of different countries over many variables, to test their level of significance. Variables that were determined statistically significant and consequently included in the equations are per-capita income, demographic growth, urbanisation, fuel prices, level of subsidies, technological advances, energy consumption, energy access programmes and policies.

To identify the more feasible access to electricity pathways the IEA uses the latest available country-by-country geospatial data to identify the least cost pathway providing connections to un-electrified populations. This assessment, using the publicly available OnSSET model, takes into account distances to the grid, expected demand, the population density and available resources to select the least cost solutions for each settlement. It then factors-in other important indicators as the potential speed at which grid and off-grid systems can provide access, the potential for simultaneously electrifying other sectors such as industry, agriculture or transport, the optimal solution for maximising reliability, resilience and quality of supply, and the attractiveness of investment to different investors and vendors.

Investment's requirements in electricity access are modelled on a base of the population gaining access by technology and latest technology cost. Investments include supply infrastructures cost for population gaining first access as electricity generation units (for grid, mini-grids and stand-alone systems), transmission (for grids) and distribution (for grids and mini-grids) lines.

Outlook for clean cooking access

Our baseline data on the traditional use of biomass for cooking is based on the World Health Organization's (WHO) Global Health Observatory estimates of reliance on solid fuels.[2] To provide an outlook for the number of people relying on the traditional use of biomass in the next decades, a regional model was developed under different assumptions. Reliance on biomass rates of different countries is projected using an econometric panel model estimated from a historical time series. Variables that were determined statistically significant and consequently included in the equations are per-capita income, demographic growth, urbanisation level, level of prices of alternative modern fuels, subsidies to alternative modern fuel consumption, technological advances and clean cooking programmes and policies. For further detail on the energy access analysis and methodology see the dedicated website: https://www.iea.org/topics/energy-access.

Investment's requirements in access to clean cooking are modelled on a base of the population gaining access by technology and latest technology costs. Investments include end-use equipment such as stoves and biodigesters as well as infrastructures for LPG (primary storage units, refilling and secondary storage, cylinders…) and electricity (additional generation and lines to power electric-cooking).

[1] https://www.iea.org/reports/sdg7-data-and-projections/access-to-electricity

[2] For more information, see www.who.int/gho/phe/indoor_air_pollution/en/index.html

Employment

The IEA added an energy employment module in 2020 and completed a fuller integration and transfer to Vensim with the GEC Model framework in 2022. Employment modelling now covers 42 energy sub-sectors for each GEC Model region under different IEA scenarios. The model currently analyses:

- The number of people currently employed in resource supply (including coal, oil, gas, bioenergy, nuclear fuel supply, critical minerals, and hydrogen), the power sector (generation, transmission, distribution, and storage), as well as major end-use sectors (vehicle manufacturing, and energy efficiency for buildings and industry); and
- The number of job losses and gains in these sectors as a direct result of shifting investments in new infrastructure, the production of energy commodities, and the operation of energy assets.

12.1 Definition and scope of employment

Employment literature typically classifies job creation impacts by the following schema:

- **Direct**: Jobs created to deliver a final project or product.
- **Indirect**: Supply chain jobs created to provide inputs to a final project or product.
- **Induced**: Jobs created by wages earned from the projects and spent in other parts of the economy, thereby creating additional jobs.

Our employment analysis includes all direct jobs and the indirect jobs from suppliers that manufacture immediate inputs to the energy sector. Other indirect jobs, as well as induced jobs are not included. In employment literature, indirect jobs sometimes include jobs "supported" by the purchase where the equipment is a key enabler for another job. For example, automobile manufacturing is a key enabler for delivery and taxi driving jobs. These "supported" jobs are not included in our analysis. This sets a clear boundary around the jobs that energy investment creates to deliver new project, or the jobs required to operate existing energy facilities.

Jobs are normalised to full-time employment (FTE) for consistent accounting. One FTE job represents one person's work for one year at regulated norms (e.g. 40 hours a week for 52 weeks a year, excluding holidays). For example, two separate, six-month jobs are counted as one FTE job. Where data is available for hours worked weekly, we calculate part-time workers with the corresponding proportion. Otherwise, part-time employment is assumed as 0.5 FTE.

Employment numbers include our best estimate of the number of informal workers, with the hope that our numbers reflect the scope of energy policy impact more completely. In alignment with International Labour Organization (ILO) guidelines, informal employment includes all remunerative work that is not registered, regulated, or protected by existing legal or regulatory frameworks (ILO, 2023). This comprises own-account workers and workers employed in informal sector enterprises; contributing family workers; employees holding informal jobs; members of informal producers' cooperatives; and own-account workers engaged in the production of goods exclusively for own final use by their own household. Estimates are based on ILO data and a literature review of informality rates by region and sector.

Categorisation by value chain step

Employment is categorised not only by energy industries, but also by value chain steps or economic sectors as defined by the International Standard Industrial Classification (ISIC) revision 4 (UN DESA, 2008), with significant numbers of workers in the following five groupings:

- **Raw materials**: Agriculture (code A) for bioenergy production and Mining and quarrying (code B) for fossil fuel production

- **Manufacturing**: ISIC code C
- **Construction**: ISIC code F
- **Professionals and utilities**: Electricity, gas, steam, and air conditioning supply (code D) as well as Professional, scientific, and technical activities (code M)
- **Wholesale and transport**: Wholesale and retail trade (code G) plus Transportation and storage (code H)

Wherever possible, we provide a comprehensive mapping of jobs across all of the above sectors.

Categorisation by asset life stage

Employment is also categorised according to whether the job is associated with building a new project or operating and maintaining existing energy infrastructure. This split is based on IEA energy balances and related data. For example, the ratio between capacity additions and installed total power capacity informs the split between power sector workers working on new projects versus existing power plants. The wording "Operations and maintenance" (O&M) is used, to refer to the workers in existing energy infrastructure or assets, as an indication of all ongoing jobs required to support the proper operation of an energy project.

Categorisation by skill level

Employment is also categorised by skill level, in harmony with the International Standard Classification of Occupations 2008 (ISCO-08) laid out by the ILO (ILO, 2023a). Skill level is defined by the ILO as "a function of the complexity and range of tasks and duties to be performed in an occupation," considering:

- The nature of work performed.
- The level of formal education required for competent performance, as defined by the International Standard Classification of Education (ISCED-97) (UNESCO, 2006).
- The amount of work experience and/or on-the-job training required for competent performance.

Table 12.4 ▹ Skill levels of employment estimates by associated education levels and occupations

Skill level	ILOSTAT skill level	Associated ISCED-97 levels	Associated ISCO-08 occupations
"High"	3-4	ISCED Level 5b: 1-3 years of study at a higher educational institute following completion of secondary education. ISCED Level 5a or higher: 3-6 years of study at a higher educational institute leading to the award of a first degree or higher qualification; formal qualifications may be required for entry to the occupation.	1. Managers 2. Professionals 3. Technicians and associate professionals
"Medium"	2	ISCED Level 2: Completion of the first stage of secondary education. ISCED Level 3: Completion of the second stage of secondary education, which may include a significant component of vocational education and/or on-the-job training. ISCED Level 4: Completion of vocation-specific education undertaken after completion of secondary education.	4. Clerical support workers 5. Service and sales workers 6. Skilled agricultural, forestry and fishery workers 7. Craft and related trades workers 8. Plant and machine operators, and assemblers
"Low"	1	ISCED Level 1: Completion of primary education or the first stage of basic education may be required, along with possible on-the-job training.	9. Elemental occupations

Table 12.4 illustrates the occupations and education levels typically observed at each skill level. In many cases, formal education is not an ideal method for approximating skill level, and as such the ISCED-97 level assigned is indicative of how workers of that skill level generally obtain the knowledge and skills required for competent performance. It is always possible that the appropriate degree of work experience and/or on-the-job training may substitute for the level of formal education indicated.

12.2 Estimating current employment

Our model uses IEA energy investment and spending data, data on energy production and consumption, power capacity and electricity generation, technology stocks and sales as the basis to estimate global employment. These datapoints are multiplied by employment multipliers tailored to each energy sub-sector to estimate total employment in the base year.

Multipliers are produced via a comprehensive literature review and using wage data for each sub-sector and region where available. They are also informed by literature review and calibrated against externally sourced employment data relevant to energy sub-sectors. Multipliers and employment estimates have been tested with companies within IEA's Energy Business Council, peer reviewers, academics, industry groups and international organisations such as the IMF and ILO.

Estimating job multipliers

Two types of multipliers are used in the model, based on investment (jobs per million US dollars invested) and volumetric data (for example, jobs per GW capacity or jobs per tonnes produced). Multipliers vary by region to reflect differences in the local cost of labour and worker productivity. They also vary by energy sub-sector, reflecting different project cost breakdowns, in other words how much of each million US dollars invested is allocated to spending on labour versus materials. The primary sources used to estimate multipliers include:

- Wage data from national statistics and international databases, for investment multipliers
- Legal financial filings that provide information on employment and revenue, cost breakdowns for projects and average wages
- Academic, intergovernmental research and modelled estimates
- Individual company and industry group estimates

Government surveys of businesses were prioritised, when available with sufficient detail, to support the sub-sectoral analysis. Employment and financial information were extracted from the annual reports of major companies in each sector, though this method could only be used for sectors with a high degree of consolidation in major firms that are publicly listed. Material from academic and industry sources was screened to ensure harmonised definitions and reference values were adjusted to adhere to the framework described. Where values from these sources were unavailable, estimates were based on employment multipliers for similar technologies. Where wage data specific to energy industries is not available, generalised wage data by region is used.

Gathering employment data

A rich collection of employment data from external sources is collected annually, to serve as benchmarks for the calibration of multipliers. These data sources included:

- National statistics for all major countries
- International Labour Organization (ILO) employment databases (ILO, 2023b)
- United Nations Industrial Development Organization (UNIDO) IndStat and MinStat databases (UNIDO, 2023a and 2023b)

- Reports by international organisations and industry associations
- Academic literature
- Annual reports of major companies
- Company interviews

Where data is collected from broad labour databases, we focus on categories relevant to energy, including the complete list of ISIC codes presented in the United Nations' *International Recommendations for Energy Statistics* (UNStat, 2011). Our scope includes codes such as 0510 (mining of hard coal), 0610 (extraction of crude petroleum, 0620 (extraction of natural gas), 1920 (manufacture of refined petroleum products), 2910 (manufacture of motor vehicles), 3510 (electric power generation, transmission and distribution), 4322 (plumbing, heat and air conditioning installation), and 4930 (transport via pipeline), and many others. A mapping between ISIC and other classifications such as the North American Industry Classification System (NAICS) or the European Nomenclature of Economic Activities (NACE) enabled a harmonised approach to collecting official statistics from different countries. Data of the highest granularity available is used in each case.

Allocating employment across global supply chains

For energy technologies with highly globalised supply chains, employment estimates reflect where in the world upstream manufacturing capacity is located, rather than where there corresponding technologies are deployed. Data about the manufacturing capacity for specific technologies (such as solar PV panels, wind turbines, gas turbines, etc.) was gathered by country or region, and the global total of manufacturing jobs was redistributed across *GEC Model* regions accordingly. For technologies that have very localised production, such as building materials and biofuels, all manufacturing jobs were assumed to be created locally.

12.3 Outlook for employment

Projections by scenario are based on IEA scenario results for all of the same inputs that were used to estimate base year employment. These are multiplied by the corresponding job multipliers – that are differentiated by region and energy industry - to estimate total jobs in coming years until 2030, and thereby estimate changes in job gains and losses relative to the base year, as well as what portion of existing jobs are maintained.

Modelling labour productivity improvements

Multipliers evolve over time to reflect assumptions about labour productivity improvements. Where industry-specific historic time series of employment and corresponding production (or another relevant metric) are available, the historic rate of change is extended forward. Where specific time series are not available, data from UN and ILO on value added by economic activity and employment by economic activity are used to compute historic labour productivity improvement rates by region and applied to future multiplier improvements.

Timing employment for new projects in the pipeline

Since our employment estimates for any given year comprise both jobs in the operations of existing assets and jobs in the build out of new projects, investment overnight values are spread across the previous years to reflect when job creation would occur, based on typical project delivery timelines. In other words, we consider for how long an investment creates jobs and in which year relative to the project delivery. For instance, investment in a new hydroelectric dam would create some jobs in the planning and preparation phase prior to the investment. When financial close occurs, these jobs disappear, but construction and equipment manufacturing jobs are created. When construction is completed, these jobs disappear, then O&M jobs begin. Jobs are assigned to the relevant years to understand total employment on an annual basis.

Government spending on clean energy and energy affordability

The IEA has been monitoring government spending dedicated to clean energy sectors since April 2020, in the framework of its *Government Energy Spending Tracker* (formerly the Sustainable Recovery Tracker) which assesses the impact of sustainable recovery policies enacted by governments in response to the Covid-19 pandemic and energy crisis. In 2022, the Agency enlarged the scope of its tracking to measures aimed at cushioning domestic consumers from the impact of the current global energy price crisis.

The IEA assessment of the impact of government spending on clean energy and energy affordability:

- Collects the amount of government spending enacted toward clean energy investment support or consumer energy affordability measures.
- Estimates the amount of private spending mobilised thanks to the clean energy investment support and incorporates it in the GEC modelling for the STEPS.

In the following section, we describe the policy collection process and how the impact on total clean energy deployment is assessed.

13.1 Policy identification and collection

Sustainable recovery policies

Sustainable recovery policies are defined as policies driving spending on clean energy investment support included in government economic recovery plans in response to the Covid-19 pandemic or the subsequent global energy crisis.

Common sustainable recovery policies include consumer or producer subsidies to develop electric vehicle markets, direct spending or public-private partnership (PPP) for building low-carbon and efficient transport infrastructures, grants for emerging energy technology pilot programmes, or tax incentives for energy-efficient building renovations.

Quantitative estimates in the Sustainable Recovery Tracker are based on national-level clean energy sector policies enacted by governments from the second quarter of 2020 until April 2022 as part of Covid-19 related recovery measures and directed toward long-term projects and measures to boost economic growth.

The following types of spending are considered in the analysis:

- **Total fiscal support:** all government spending disbursed from 2020 in response to the Covid-19 crisis, in the form of additional spending and/or forgone revenue, as per the IMF Fiscal Monitor definition. This includes short-term economic relief payments to citizens and firms to weather the effects of the pandemic.
- **Economic recovery spending:** government spending directed to long-term projects and measures to boost growth, a subset of total fiscal support. Examples include infrastructure projects like roads, broadband internet, public housing upgrades, incentives for business improvements etc. Many governments tended to turn to these long-term perspective policies from the second quarter of 2020, after having precedents concentrated on emergency economic and health support. This does not include economic relief payments to citizens and firms; and only includes spending that is directed specifically to new investments.
- **Government spending on sustainable recovery measures**: government spending targeting clean energy investment support, a subset of economic recovery spending. This includes consumer or producer subsidies, tax breaks, public procurement, loan guarantees, PPP contracts and other co-funding schemes favoured by governments. Only direct government fiscal spending from the second quarter of 2020 is considered, spending directed by regulators to state-owned enterprises (SOEs) or publicly regulated entities being set aside.

The last two categories, which encompass government and total mobilised sustainable recovery spending, were compared on a sectoral and regional basis, in six key sectors: low-carbon electricity, electricity networks, low-carbon and efficient transport, energy efficient buildings and industry, cleaner fuels and emerging low-carbon technologies.

Only additional recovery spending aimed at creating new assets or extending the life of existing low-carbon infrastructure is considered. Accordingly, Covid-19-related liquidity measures for energy companies or energy intensive industries are not directly incorporated since they do not support additional low-carbon activities. However, as supporting energy firms through the pandemic preserves their ability to attract investment, this benefit is captured in calibrating sectoral factors assessing mobilised private spending, together with policies generally ameliorating the investment environment.

Energy crisis response policies

Affordability support includes emergency consumer support enacted by governments in response to the international price rise that materialised in the fourth quarter of 2021 and was further aggravated by Russia's invasion of Ukraine. The most common policy instruments include temporary consumer subsidies or tax alleviation/exemption, state-backed loans or price regulation mechanisms, often enacted as temporary measures. The spending is assessed from the government's perspective, as direct budget allocation, foregone tax revenues etc.

Quantitative estimates from energy crisis response policies are based on policies enacted by governments between September 2021 and September 2022, and are derived exclusively from official government estimates of the total direct cost of supporting those measures borne by governments. Accordingly, they do not capture other forms of sub-market price subsidies that may be channelled through utilities and other energy-related state-owned enterprises.

Collection process

The IEA independently collects data on recovery policies, in co-operation with its members, as well as G20 members.

All policies considered in the Sustainable Recovery Tracker, alongside their corresponding budgets, are available in the IEA Policies and Measures (PAMS) Database, a unique repository that has aggregated energy policies over the past two decades, bringing together data from the IEA Energy Efficiency Database, the Addressing Climate Change database, the Buildings Energy Efficiency Policies database and the IEA/IRENA Renewable Energy Policies and Measures Database, along with information on CCUS, critical minerals and methane abatement policies. Each record includes a concise summary of the policy and links to the original source, and is tagged by policy type, technology and sector.

Among the thousands of policies in the PAMS database are 1 500 sustainable recovery and energy affordability policies covering around 70 countries. Government sustainable recovery spending is recorded and attributed to the timelines officially enacted, according to available information. Total mobilised sustainable recovery spending is spread evenly across all announced years. Each budget item is also tagged with the sustainable recovery measure it targets.

13.2 Assessing the impact on overall clean energy investment

The impact of government recovery spending on overall clean energy deployment is assessed using mobilisation factors per sector and geography. This assessment is used to assess the impact of the latest policies but is not used as an estimate for total clean energy investment, which instead flows from the main GEC Model outputs.

The ability for government spending to crowd-in private investment varies greatly across contexts, and depends on many different factors, ranging from the type, scale and temporality of the fiscal intervention to aspects inherent to local economic and financial contexts and, increasingly, global commercial trends.

The approach chosen seeks to approximate this mobilisation effect based on a limited number of known factors, partly drawn from historical trends. The evaluation is continuously complemented and enhanced as data becomes available, notably on the evolution of the economic crisis in different regions as well as on the ex-post assessments of Covid-19 recovery policies. The IEA aims at refining this modelling approach, in particular to try to better assess how a specific policy type improves efficacy of public dollars mobilised, and calibrating the approach based on real investment seen in the field.

Assessing mobilisation factors for clean energy investment support

Past mobilisation factors (one per technology per region) were derived from historical levels of investment and government support, drawing from the IEA's energy investment database. These historical mobilisation factors were then calibrated to reflect changing investment conditions. The IEA used a series of indices, pulled from IEA data or global financial sources, to help calibrate the mobilisation factors. These indices can use raw data points (e.g. GDP growth), binary variables (e.g. is this supporting policy available in the region), and expert rating variables (e.g. on a scale of 1-5, how mature is the XX market in region YY). The indices used for this calibration include:

- **Macroeconomic factors**: GDP growth rate, cost of capital, credit risk rating of the country/region.
- **Energy industry health**: whether liquidity support was made available, maturity of the market for the specific clean energy measure in question.
- **Supporting policy environment**: the presence of supporting non-fiscal policies (e.g. priority parking for electric vehicles), market or pricing mechanisms supportive of deployment (e.g. special all-electric utility rates), degree of administrative support/burden (e.g. typical timelines for permitting approval), effectiveness/maturity of policy mechanisms deployed (e.g. how many years has the policy been in place).
- **Cost-effectiveness**: payback period for the measures or cost-competitiveness against alternatives (e.g. LCOEs).

Determining implementation timelines

Many sustainable recovery policies are targeting projects or investments that will not materialise in the near-term (e.g. offshore wind projects with long lead times, or CCUS pilots). It also considers how some spending is meant to lay the groundwork for increased long-term private sector spending or involvement (e.g. port and fuelling infrastructure, and support to innovation). The analysis determines when the total sustainable recovery spending mobilised actually materialised on-the-ground by taking into account three specific steps and associated delays:

- average time from policy announcement to disbursement for viable projects (from policy assessments conducted at the IEA).
- average time from financial closure to effective operation (from our World Energy Investment data).
- average delay for certain government supports (e.g. supporting infrastructure, innovation funding, research, market reforms) to materialise their impacts (estimated based on large infrastructure project timelines).

The first two are reflected by delaying the year when those investments come on relative to the year the funding is enacted. The last is by increasing the private spending mobilisation factor for subsequent years.

Annex A: Terminology

This annex provides general information on terminology used throughout this report including: definitions of fuels, processes and sectors; regional and country groupings; and abbreviations and acronyms.

Definitions

Advanced bioenergy: Sustainable fuels produced from wastes and residues and non-food crop feedstocks (excluding traditional uses of biomass), which are capable of delivering significant life cycle greenhouse gas emissions savings compared with fossil fuel alternatives and of minimising adverse sustainability impacts. Advanced bioenergy feedstock either do not directly compete with food and feed crops for agricultural land or are only developed on land previously used to produced food crop feedstocks for biofuels. This definition differs from the one used for "advanced biofuels" in US legislation, which is based on a minimum 50% life cycle greenhouse gas reduction and, therefore, includes sugar cane ethanol.

Agriculture: Includes all energy used on farms, in forestry and for fishing.

Agriculture, forestry and other land use (AFOLU) **emissions:** Includes greenhouse gas emissions from agriculture, forestry and other land use.

Ammonia (NH_3)**:** A compound of nitrogen and hydrogen that can be used as a feedstock in the chemical sector, as a fuel in direct combustion processes in fuel cells, or as a hydrogen carrier. To be a low-emissions fuel, ammonia must be produced from hydrogen that is itself produced using electricity generated from low-emissions sources, and nitrogen separated via the Haber process using electricity generated from low-emissions sources.

Aviation: This transport mode includes both domestic and international flights and their use of aviation fuels. Domestic aviation covers flights that depart and land in the same country as well as flights for military purposes. International aviation includes flights that land in a country other than the departure location.

Back-up generation capacity: Households and businesses connected to the main power grid may also have some form of back-up power generation capacity that, in the event of disruption, can provide electricity. Back-up generators are typically fuelled with diesel or gasoline. Capacity can be as little as a few kilowatts. Such capacity is distinct from mini-grid and off-grid systems that are not connected to a main power grid.

Battery storage: Energy storage technology that uses reversible chemical reactions to absorb and release electricity on demand.

Biodiesel: Diesel-equivalent, processed fuel made from the transesterification (a chemical process that converts triglycerides in oils) of vegetable oils and animal fats.

Bioenergy: Energy content in solid, liquid and gaseous products derived from biomass feedstocks and biogas. It includes solid bioenergy, liquid biofuels and biogases.

Bioenergy with carbon, capture, and storage (BECCS): Technology involving any energy pathway where CO_2 is captured from a biogenic source (e.g. biofuel plant) and permanently stored.

Biogas: A mixture of methane, CO_2 and small quantities of other gases produced by anaerobic digestion of organic matter in an oxygen-free environment.

Biogases: Include both biogas and biomethane.

Biojet kerosene: Kerosene substitute produced from biomass, via conversion routes such as hydroprocessed esters and fatty acids (HEFA) and biomass gasification with Fischer-Tropsch. It excludes synthetic kerosene produced from biogenic carbon dioxide.

Biomethane: Biomethane is a near-pure source of methane produced either by "upgrading" biogas (a process that removes any CO_2 and other contaminants present in the biogas) or through the gasification of solid biomass followed by methanation. It is also known as renewable natural gas.

Buildings: Includes energy used in residential and services buildings. Services buildings include commercial and institutional buildings and other non-specified buildings. Building energy use includes space heating and cooling, water heating, lighting, appliances and cooking equipment.

Bunkers: Includes both international marine bunkers and international aviation bunkers.

Capacity credit: Proportion of the capacity that can be reliably expected to generate electricity during times of peak demand in the grid to which it is connected.

Carbon capture, utilisation and storage (CCUS)**:** The process of capturing CO_2 emissions from fuel combustion, industrial processes or directly from the atmosphere. Captured CO_2 emissions can be stored in underground geological formations, onshore or offshore, or used as an input or feedstock in manufacturing.

Carbon dioxide (CO_2)**:** A gas consisting of one part carbon and two parts oxygen. It is an important greenhouse (heat-trapping) gas.

Carbon dioxide removal (CDR)**:** Process resulting in permanent removal of CO_2 from the atmosphere. In the GEC model, this can be achieved through permanently storing CO_2 captured from biogenic sources (BECCS) or from the air (DACS).

Clean cooking systems, fuels stoves and technologies: Cooking solutions that release less harmful pollutants, are more efficient and environmentally sustainable than traditional cooking options that make use of solid biomass (such as a three-stone fire), coal or kerosene. This refers primarily to improved solid biomass cookstoves (ISO Tier >2), biogas/biodigester systems, electric stoves, liquefied petroleum gas, natural gas or ethanol stoves.

Clean energy: In *power*, clean energy includes: generation from renewable sources, nuclear and fossil fuels fitted with CCUS; battery storage; and electricity grids. In *efficiency*, clean energy includes energy efficiency in buildings, industry and transport, excluding aviation bunkers and domestic navigation. In *end-use* applications, clean energy includes: direct use of renewables; electric vehicles; electrification in buildings, industry and international marine transport; use of hydrogen and hydrogen-based fuels; CCUS in industry and direct air carbon capture and storage. In *fuel supply*, clean energy includes low emissions fuels liquid biofuels and biogases, low-carbon hydrogen and hydrogen-based fuels.

Coal: Includes both primary coal (i.e. lignite, coking and steam coal) and derived fuels (e.g. patent fuel, brown-coal briquettes, coke-oven coke, gas coke, gas works gas, coke-oven gas, blast furnace gas and oxygen steel furnace gas). Peat is also included.

Coalbed methane (CBM)**:** Category of unconventional natural gas, which refers to methane found in coal seams.

Coal-to-gas (CTG)**:** Process in which mined coal is first turned into syngas (a mixture of hydrogen and carbon monoxide) and then into synthetic methane.

Coal-to-liquids (CTL)**:** Transformation of coal into liquid hydrocarbons. It can be achieved through either coal gasification into syngas (a mixture of hydrogen and carbon monoxide), combined using the Fischer-Tropsch or methanol-to-gasoline synthesis process to produce liquid fuels, or through the less developed direct-coal liquefaction technologies in which coal is directly reacted with hydrogen.

Coking coal: Type of coal that can be used for steel making (as a chemical reductant and a source of heat), where it produces coke capable of supporting a blast furnace charge. Coal of this quality is also commonly known as metallurgical coal.

Concentrating solar power (CSP)**:** Solar thermal power generation technology that collects and concentrates sunlight to produce high temperature heat to generate electricity.

Conventional liquid biofuels: Fuels produced from food crop feedstocks. Commonly referred to as first generation biofuels and include sugar cane ethanol, starch-based ethanol, fatty acid methyl ester (FAME), straight vegetable oil (SVO) and hydrotreated vegetable oil (HVO) produced from palm, rapeseed or soybean oil.

Decomposition analysis: Statistical approach that decomposes an aggregate indicator to quantify the relative contribution of a set of pre-defined factors leading to a change in the aggregate indicator. The GEC Model uses an additive index decomposition of the type Logarithmic Mean Divisia Index (LMDI).

Demand-side integration (DSI)**:** Consists of two types of measures: actions that influence load shape such as energy efficiency and electrification; and actions that manage load such as demand-side response.

Demand-side response (DSR)**:** Describes actions which can influence the load profile such as shifting the load curve in time without affecting total electricity demand, or load shedding such as interrupting demand for a short duration or adjusting the intensity of demand for a certain amount of time.

Direct air capture (DAC)**:** A type of CCUS that captures CO_2 directly from the atmosphere using liquid solvents or solid sorbents. It is generally coupled with permanent storage of the CO_2 in deep geological formations or its use in the production of fuels, chemicals, building materials or other products. When coupled with permanent geological CO_2 storage, DAC is a carbon removal technology, and it is known as direct air capture and storage (DACS).

Dispatchable generation: Refers to technologies whose power output can be readily controlled, i.e. increased to maximum rated capacity or decreased to zero, in order to match supply with demand.

Electricity demand: Defined as total gross electricity generation less own use generation, plus net trade (imports less exports), less transmission and distribution losses.

Electricity generation: Defined as the total amount of electricity generated by power only or combined heat and power plants including generation required for own use. This is also referred to as gross generation.

End-use sectors: Includes industry (i.e. manufacturing, mining, chemical production, blast furnaces and coke ovens), transport, buildings (i.e. residential and services) and other (i.e. agriculture and other non-energy use).

Energy-intensive industries: Includes the production and manufacturing of iron and steel, chemicals, non-metallic minerals (including cement), non-ferrous metals (including aluminium), and paper, pulp and printing.

Energy-related and industrial process CO_2 emissions: Carbon dioxide emissions from fuel combustion and from industrial processes. Note that this does not include fugitive emissions from fuels, flaring or CO_2 from transport and storage. Unless otherwise stated, CO_2 emissions reported from the GEC Model refer to energy-related and industrial process CO_2 emissions.

Energy sector greenhouse gas (GHG) **emissions:** Energy-related and industrial process CO_2 emissions plus fugitive and vented methane (CH_4) and nitrous dioxide (N_2O) emissions from the energy and industry sectors.

Energy services: See useful energy.

Ethanol: Refers to bio-ethanol only. Ethanol is produced from fermenting any biomass high in carbohydrates. Currently, ethanol is made from starches and sugars, but second generation technologies will allow it to be made from cellulose and hemicellulose, the fibrous material that makes up the bulk of most plant matter.

Fischer-Tropsch synthesis: Catalytic production process for the production of synthetic fuels. Natural gas, coal and biomass feedstocks can be used.

Fossil fuels: Include coal, natural gas, oil and peat.

Gaseous fuels: Include natural gas, biogases, synthetic methane, and hydrogen.

Gases: See gaseous fuels.

Gas-to-liquids (GTL)**:** Process featuring reaction of methane with oxygen or steam to produce syngas (a mixture of hydrogen and carbon monoxide) followed by synthesis of liquid products (such as diesel and naphtha) from the syngas using Fischer-Tropsch catalytic synthesis. The process is similar to that used in coal-to-liquids.

Geothermal: Geothermal energy is heat derived from the sub-surface of the earth. Water and/or steam carry the geothermal energy to the surface. Depending on its characteristics, geothermal energy can be used for heating and cooling purposes or be harnessed to generate clean electricity if the temperature is adequate.

Heat (end-use): Can be obtained from the combustion of fossil or renewable fuels, direct geothermal or solar heat systems, exothermic chemical processes and electricity (through resistance heating or heat pumps which can extract it from ambient air and liquids). This category refers to the wide range of end-uses, including space and water heating and cooking in buildings, desalination and process applications in industry. It does not include cooling applications.

Heat (supply): Obtained from the combustion of fuels, nuclear reactors, geothermal resources and the capture of sunlight. It may be used for heating or cooling, or converted into mechanical energy for transport or electricity generation. Commercial heat sold is reported under total final consumption with the fuel inputs allocated under power generation.

Heavy industries: Iron and steel, chemicals and cement.

Hydrogen: Hydrogen is used in the energy system as an energy carrier, as an industrial raw material, or combined with other inputs to produce hydrogen-based fuels. Unless otherwise stated, hydrogen refers to low-emissions hydrogen.

Hydrogen-based fuels: See low-emissions hydrogen-based fuels.

Hydropower: The energy content of the electricity produced in hydropower plants, assuming 100% efficiency. It excludes output from pumped storage and marine (tide and wave) plants.

Improved cookstoves: Intermediate and advanced improved biomass cookstoves (ISO tier >2). It excludes basic improved cookstoves (ISO tier 0-2).

Industry: The sector includes fuel used within the manufacturing and construction industries. Key industry branches include iron and steel, chemical and petrochemical, cement, aluminium, and pulp and paper. Use by industries for the transformation of energy into another form or for the production of fuels is excluded and reported separately under other energy sector. There is an exception for fuel transformation in blast furnaces and coke ovens, which are reported within iron and steel. Consumption of fuels for the transport of goods is reported as part of the transport sector, while consumption by off-road vehicles is reported under industry.

International aviation bunkers: Includes the deliveries of aviation fuels to aircraft for international aviation. Fuels used by airlines for their road vehicles are excluded. The domestic/international split is determined on the basis of departure and landing locations and not by the nationality of the airline. For many countries this incorrectly excludes fuels used by domestically owned carriers for their international departures.

International marine bunkers: Covers those quantities delivered to ships of all flags that are engaged in international navigation. The international navigation may take place at sea, on inland lakes and waterways, and in coastal waters. Consumption by ships engaged in domestic navigation is excluded. The domestic/international split is determined on the basis of the port of departure and port of arrival, and not by the flag or nationality of the ship. Consumption by fishing vessels and by military forces is excluded and instead included in the residential, services and agriculture category.

Investment: Investment is measured as the ongoing capital spending in energy supply capacity, energy infrastructure and energy end-use and efficiency. All investment data and projections reflect spending across the lifecycle of a project, i.e. the capital spent is assigned to the year when it is incurred. Fuel supply investments include production, transformation and transportation for oil, gas, coal and low emissions fuels. Power sector investments include new builds and refurbishments of generation, electricity grids (transmission, distribution and public electric vehicle chargers), and battery storage. Energy efficiency investments include those made in buildings, industry and transport. Other end-use investments include direct use of renewables; electric vehicles; electrification in buildings, industry and international marine transport; use of hydrogen and hydrogen-based fuels; fossil fuel-based industrial facilities; CCUS in industry and DACS/DACU. Investment data are presented in real terms in year-2023 US dollars unless otherwise stated.

Light-duty vehicles (LDVs)**:** Includes passenger cars and light commercial vehicles (gross vehicle weight <3.5 tonnes).

Light industries: Includes non-energy-intensive industries: food and tobacco, machinery, mining and quarrying, transportation equipment, textile, wood harvesting and processing and construction.

Lignite: Type of coal that is used in the power sector mostly in regions near lignite mines due to its low energy content and typically high moisture levels, which generally makes long-distance transport uneconomic. Data on lignite in the GEC Model includes peat, a solid formed from the partial decomposition of dead vegetation under conditions of high humidity and limited air access.

Liquid biofuels: Liquid fuels derived from biomass or waste feedstock and include ethanol, biodiesel and biojet fuels. They can be classified as conventional and advanced biofuels according to the combination of feedstock and technologies used to produce them and their respective maturity. Unless otherwise stated, biofuels are expressed in energy-equivalent volumes of gasoline, diesel and kerosene.

Liquid fuels: Includes oil, liquid biofuels (expressed in energy-equivalent volumes of gasoline and diesel), synthetic oil and ammonia.

Low-carbon electricity: Includes renewable energy technologies, hydrogen-based generation, nuclear power and fossil fuel power plants equipped with carbon capture, utilisation and storage.

Lower heating value: Heat liberated by the complete combustion of a unit of fuel when the water produced is assumed to remain as a vapour and the heat is not recovered.

Low-emissions fuels: Include modern bioenergy, low-emissions hydrogen and low-emissions synthetic methane.

Low-emissions hydrogen-based fuels: Include ammonia, methanol, and other synthetic hydrocarbons (gases and liquids) made from low-emissions hydrogen. Any carbon inputs, e.g. from CO_2, are not from fossil fuels or process emissions. Hydrogen-based is used in the figures in publications using the GEC Model to refer to hydrogen and hydrogen-based fuels.

Low-emissions hydrogen-based liquid fuels: A subset of low-emissions hydrogen-based fuels that includes only ammonia, methanol and synthetic liquid hydrocarbons, such as synthetic kerosene.

Marine energy: Represents the mechanical energy derived from tidal movement, wave motion or ocean currents and exploited for electricity generation.

Middle distillates: Include jet fuel, diesel and heating oil.

Mini-grids: Small electric grid systems, not connected to main electricity networks, linking a number of households and/or other consumers.

Modern energy access: Includes household access to a minimum level of electricity; household access to less harmful and more sustainable cooking and heating fuels, and stoves; access that enables productive economic activity; and access for public services.

Modern gaseous bioenergy: See biogases.

Modern liquid bioenergy: Includes bio-gasoline, biodiesel, biojet kerosene and other liquid biofuels.

Modern renewables: Include all uses of renewable energy with the exception of traditional use of solid biomass.

Modern solid bioenergy: Includes all solid bioenergy products (see solid bioenergy definition) except the traditional use of biomass. It also includes the use of solid bioenergy in intermediate and advanced improved biomass cookstoves (ISO tier > 2) requiring fuel to be cut in small pieces or often using processed biomass such as pellets.

Natural gas: Comprises gases occurring in deposits, whether liquefied or gaseous, consisting mainly of methane. It includes both non-associated gas originating from fields producing hydrocarbons only in gaseous form, and associated gas produced in association with crude oil as well as methane recovered from coal mines (colliery gas). Natural gas liquids, manufactured gas (produced from municipal or industrial waste, or sewage) and quantities vented or flared are not included. Gas data in cubic metres are expressed on a gross calorific value basis and are measured at 15 °C and at 760 mm Hg (Standard Conditions). Gas data expressed in tonnes of oil equivalent, mainly for comparison reasons with other fuels, are on a net calorific basis. The difference between the net and the gross calorific value is the latent heat of vaporization of the water vapour produced during combustion of the fuel (for gas the net calorific value is 10% lower than the gross calorific value).

Natural gas liquids (NGLs)**:** Liquid or liquefied hydrocarbons produced in the manufacture, purification and stabilisation of natural gas. NGLs are portions of natural gas recovered as liquids in separators, field facilities or gas processing plants. NGLs include, but are not limited to, ethane (when it is removed from the natural gas stream), propane, butane, pentane, natural gasoline and condensates.

Near zero emission capable material production capacity: Capacity that will achieve substantial emissions reductions from the start – but fall short of near zero emission material production (see following definition) initially – with plans to continue reducing emissions over time such that they could later achieve near zero emission production without additional capital investment.

Near zero emission material production: For steel and cement, production that achieves the near zero emission GHG emissions intensity thresholds defined in the IEA's 'Achieving Net Zero Heavy Industry Sectors in G7 Members' (2022b); the thresholds depend on the scrap share of metallics input for steel and the clinker-to-cement ratio for cement. For other energy-intensive commodities like aluminium, fertilisers and plastics, production that achieves reductions in emissions intensity equivalent to the considerations for near zero emission steel and cement.

Near zero emission material production capacity: Capacity that, once operational, will achieve near zero emission material production (see preceding definition) from the start.

Network gases: Include natural gas, biomethane, synthetic methane and hydrogen blended in a gas network.

Non-energy use: Fuels used for chemical feedstocks and non-energy products. Examples of non-energy products include lubricants, paraffin waxes, asphalt, bitumen, coal tars and oils as timber preservatives.

Non-renewable waste: Non-biogenic waste such as plastics in municipal or industrial waste.

Nuclear: Refers to the primary energy equivalent of the electricity produced by a nuclear power plant, assuming an average conversion efficiency of 33%.

Off-grid systems: Stand-alone systems for individual households or groups of consumers.

Offshore wind: Refers to electricity produced by wind turbines installed in open water, usually in the ocean.

Oil: Includes both conventional and unconventional oil production. Petroleum products include refinery gas, ethane, liquid petroleum gas, aviation gasoline, motor gasoline, jet fuels, kerosene, gas/diesel oil, heavy fuel oil, naphtha, white spirits, lubricants, bitumen, paraffin, waxes and petroleum coke.

Other energy sector: Covers the use of energy by transformation industries and the energy losses in converting primary energy into a form that can be used in the final consuming sectors. It includes losses in the production of low-emissions hydrogen and hydrogen-based fuels, bioenergy processing, gas works, petroleum refining, coal and gas transformation and liquefaction. It also includes energy own use in coal mines, in oil and gas extraction and in electricity and heat production. Transfers and statistical differences are also included in this category. Fuel transformation in blast furnaces and coke ovens are not accounted for in this category.

Other industry: A category of industry branches that includes construction, food processing, machinery, mining, textiles, transport equipment, wood processing and remaining industry. It is sometimes referred to as non-energy-intensive industries.

Passenger cars: A road motor vehicle, other than a moped or a motorcycle, intended to transport passengers. It includes vans designed and used primarily to transport passengers. It excludes light commercial vehicles, motor coaches, urban buses, and mini-buses/mini-coaches.

Power generation: Refers to fuel use in electricity plants, heat plants and combined heat and power plants. Both main activity producer plants and small plants that produce fuel for their own use (auto-producers) are included.

Process emissions: CO_2 emissions produced from industrial processes which chemically or physically transform materials. A notable example is cement production, in which CO_2 is emitted when calcium carbonate is transformed into lime, which in turn is used to produce clinker.

Productive uses: Energy used towards an economic purpose: agriculture, industry, services and non-energy use. Some energy demand from the transport sector (e.g. freight) could be considered as productive, but is treated separately.

Rare earth elements (REEs): A group of 17 chemical elements in the periodic table, specifically the 15 lanthanides plus scandium and yttrium. REEs are key components in some clean energy technologies, including wind turbines, EV motors and electrolysers.

Renewables: Includes bioenergy, geothermal, hydropower, solar photovoltaics (PV), concentrating solar power (CSP), wind and marine (tide and wave) energy for electricity and heat generation.

Residential: Energy used by households including space heating and cooling, water heating, lighting, appliances, electronic devices and cooking.

Road transport: Includes all road vehicle types (passenger cars, two/three-wheelers, light commercial vehicles, buses and medium and heavy freight trucks).

Services: Energy used in commercial facilities, e.g. offices, shops, hotels, restaurants, and in institutional buildings, e.g. schools, hospitals, public offices. Energy use in services includes space heating and cooling, water heating, lighting, appliances, cooking and desalination.

Shale gas: Natural gas contained within a commonly occurring rock classified as shale. Shale formations are characterised by low permeability, with more limited ability of gas to flow through the rock than is the case within a conventional reservoir. Shale gas is generally produced using hydraulic fracturing.

Shipping/navigation: This transport sub-sector includes both domestic and international navigation and their use of marine fuels. Domestic navigation covers the transport of goods or people on inland waterways and for national sea voyages (starts and ends in the same country without any intermediate foreign port). International navigation includes quantities of fuels delivered to merchant ships (including passenger ships) of any nationality for consumption during international voyages transporting goods or passengers.

Solar: Includes solar photovoltaics and concentrating solar power.

Solar photovoltaics (PV)**:** Electricity produced from solar photovoltaic cells.

Solid bioenergy: Includes charcoal, fuelwood, dung, agricultural residues, wood waste and other solid wastes.

Solid fuels: Include coal, modern solid bioenergy, traditional use of biomass and industrial and municipal wastes.

Steam coal: Type of coal that is mainly used for heat production or steam-raising in power plants and, to a lesser extent, in industry. Typically, steam coal is not of sufficient quality for steel making. Coal of this quality is also commonly known as thermal coal.

Synthetic methane: Low-carbon synthetic methane is produced through the methanation of low-carbon hydrogen and carbon dioxide from a biogenic or atmospheric source.

Synthetic oil: Low-carbon synthetic oil produced through Fischer-Tropsch conversion or methanol synthesis from syngas, a mixture of hydrogen (H_2) and carbon monoxide (CO).

Tight oil: Oil produced from shale or other very low permeability formations, generally using hydraulic fracturing. This is also sometimes referred to as light tight oil. Tight oil includes tight crude oil and condensate production except for the United States, which includes tight crude oil only (US tight condensate volumes are included in natural gas liquids).

Total energy supply (TES)**:** Represents domestic demand only and is broken down into electricity and heat generation, other energy sector and total final consumption.

Total final consumption (TFC)**:** The sum of consumption by the various end-use sectors. TFC is broken down into energy demand in the following sectors: industry (including manufacturing, mining, chemicals production, blast furnaces and coke ovens), transport, buildings (including residential and services) and other (including agriculture and other non-energy use). It excludes international marine and aviation bunkers, except at world level where it is included in the transport sector.

Total final energy consumption (TFEC)**:** A variable defined primarily for tracking progress towards target 7.2 of the United Nations Sustainable Development Goals. It incorporates total final consumption by end-use sectors but excludes non-energy use. It excludes international marine and aviation bunkers, except at world level. Typically, this is used in the context of calculating the renewable energy share in total final energy consumption (Sustainable Development Goal 7.2.1), where TFEC is the denominator.

Total primary energy demand (TPED)**:** See total energy supply.

Traditional use of biomass: The use of solid biomass with basic technologies, such as a three-stone fire or basic stoves (ISO Tier 0-2), often with no or poorly operating chimneys.

Transport: Fuels and electricity used in the transport of goods or people within the national territory irrespective of the economic sector within which the activity occurs. This includes fuel and electricity delivered to vehicles using public roads or for use in rail vehicles; fuel delivered to vessels for domestic navigation; fuel delivered to aircraft for domestic aviation; and energy consumed in the delivery of fuels through pipelines. Fuel delivered to international marine and aviation bunkers is presented only at the world level and is excluded from the transport sector at a domestic level.

Trucks: Includes all size categories of commercial vehicles: light trucks (gross vehicle weight less than 3.5 tonnes); medium freight trucks (gross vehicle weight 3.5 to 15 tonnes); and heavy freight trucks (>15 tonnes).

Unabated coal: Consumption of coal in facilities without CCUS.

Unabated fossil fuel use: Consumption of fossil fuels in facilities without CCUS.

Unabated gas: Consumption of natural gas in facilities without CCUS.

Useful energy: The energy that is available to end-users to satisfy their needs. This is also referred to as energy services demand. As result of transformation losses at the point of use, the amount of useful energy is lower than the corresponding final energy demand for most technologies. Equipment using electricity often has higher conversion efficiency than equipment using other fuels, meaning that for a unit of energy consumed, electricity can provide more energy services.

Value-adjusted levelised cost of electricity (VALCOE): Incorporates information on both costs and the value provided to the system. Based on the LCOE, estimates of energy, capacity and flexibility value are incorporated to provide a more complete metric of competitiveness for power generation technologies.

Variable renewable energy (VRE): Refers to technologies whose maximum output at any time depends on the availability of fluctuating renewable energy resources. VRE includes a broad array of technologies such as wind power, solar PV, run-of-river hydro, concentrating solar power (where no thermal storage is included) and marine (tidal and wave).

Zero-carbon-ready buildings: A zero-carbon-ready building is highly energy efficient and either uses renewable energy directly or an energy supply that can be fully decarbonised, such as electricity or district heat.

Zero emissions vehicles (ZEVs): Vehicles that are capable of operating without tailpipe CO_2 emissions (battery electric and fuel cell vehicles).

Regional and country groupings

Results from the *GEC Model* are often presented with the below regional groupings:

Advanced economies: OECD regional grouping and Bulgaria, Croatia, Cyprus[1,2], Malta and Romania.

Africa: North Africa and sub-Saharan Africa regional groupings.

Asia Pacific: Southeast Asia regional grouping and Australia, Bangladesh, Democratic People's Republic of Korea (North Korea), India, Japan, Korea, Mongolia, Nepal, New Zealand, Pakistan, People's Republic of China (China), Sri Lanka, Chinese Taipei, and other Asia Pacific countries and territories.[3]

Caspian: Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyzstan, Tajikistan, Turkmenistan and Uzbekistan.

Central and South America: Argentina, Plurinational State of Bolivia (Bolivia), Brazil, Chile, Colombia, Costa Rica, Cuba, Curaçao, Dominican Republic, Ecuador, El Salvador, Guatemala, Guyana, Haiti, Honduras, Jamaica, Nicaragua, Panama, Paraguay, Peru, Suriname, Trinidad and Tobago, Uruguay, Bolivarian Republic of Venezuela (Venezuela), and other Central and South American countries and territories.[4]

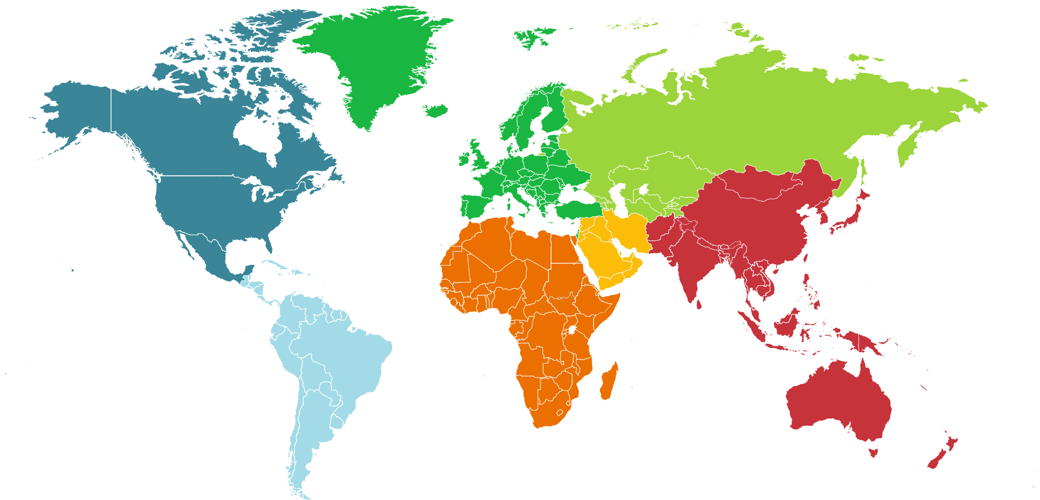
China: Includes the (People's Republic of) China and Hong Kong, China.

Developing Asia: Asia Pacific regional grouping excluding Australia, Japan, Korea and New Zealand.

Emerging market and developing economies: All other countries not included in the advanced economies regional grouping.

Eurasia: Caspian regional grouping and the Russian Federation (Russia).

Figure A.1 ⊳ GEC Model regional groupings



Note: This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Europe: European Union regional grouping and Albania, Belarus, Bosnia and Herzegovina, North Macedonia, Gibraltar, Iceland, Israel[5], Kosovo, Montenegro, Norway, Serbia, Switzerland, Republic of Moldova, Republic of Türkiye, Ukraine and United Kingdom.

European Union: Austria, Belgium, Bulgaria, Croatia, Cyprus[1,2], Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, Slovak Republic, Slovenia, Spain and Sweden.

IEA (International Energy Agency): OECD regional grouping excluding Chile, Iceland, Israel, Latvia, Lithuania and Slovenia.

Latin America and the Caribbean: Central and South America regional grouping and Mexico.

Middle East: Bahrain, Islamic Republic of Iran (Iran), Iraq, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syrian Arab Republic (Syria), United Arab Emirates and Yemen.

Non-OECD: All other countries not included in the OECD regional grouping.

Non-OPEC: All other countries not included in the OPEC regional grouping.

North Africa: Algeria, Egypt, Libya, Morocco and Tunisia.

North America: Canada, Mexico and United States.

OECD (Organisation for Economic Co-operation and Development): Australia, Austria, Belgium, Canada, Chile, Costa Rica, Czech Republic, Colombia, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Israel, Italy, Japan, Korea, Latvia, Lithuania, Luxembourg, Mexico, Netherlands, New Zealand, Norway, Poland, Portugal, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Republic of Türkiye, United Kingdom and United States.

OPEC (Organisation of the Petroleum Exporting Countries): Algeria, Angola, Republic of the Congo (Congo), Equatorial Guinea, Gabon, the Islamic Republic of Iran (Iran), Iraq, Kuwait, Libya, Nigeria, Saudi Arabia, United Arab Emirates and Bolivarian Republic of Venezuela (Venezuela).

Southeast Asia: Brunei Darussalam, Cambodia, Indonesia, Lao People's Democratic Republic (Lao PDR), Malaysia, Myanmar, Philippines, Singapore, Thailand and Viet Nam. These countries are all members of the Association of Southeast Asian Nations (ASEAN).

Sub-Saharan Africa: Angola, Benin, Botswana, Cameroon, Republic of the Congo (Congo), Côte d'Ivoire, Democratic Republic of the Congo, Equatorial Guinea, Eritrea, Ethiopia, Gabon, Ghana, Kenya, Kingdom of Eswatini, Madagascar, Mauritius, Mozambique, Namibia, Niger, Nigeria, Rwanda, Senegal, South Africa, South Sudan, Sudan, United Republic of Tanzania (Tanzania), Togo, Uganda, Zambia, Zimbabwe and other African countries and territories.[6]

Country notes

[1] Note by the Republic of Türkiye: The information in this document with reference to "Cyprus" relates to the southern part of the island. There is no single authority representing both Turkish and Greek Cypriot people on the island. Türkiye recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of the United Nations, Türkiye shall preserve its position concerning the "Cyprus issue".

[2] Note by all the European Union Member States of the OECD and the European Union: The Republic of Cyprus is recognised by all members of the United Nations with the exception of the Republic of Türkiye. The information in this document relates to the area under the effective control of the Government of the Republic of Cyprus.

[3] Individual data are not available and are estimated in aggregate for: Afghanistan, Bhutan, Cook Islands, Fiji, French Polynesia, Kiribati, Macau (China), Maldives, New Caledonia, Palau, Papua New Guinea, Samoa, Solomon Islands, Timor-Leste and Tonga and Vanuatu.

[4] Individual data are not available and are estimated in aggregate for: Anguilla, Antigua and Barbuda, Aruba, Bahamas, Barbados, Belize, Bermuda, Bonaire, Sint Eustatius and Saba, British Virgin Islands, Cayman Islands, Dominica, Falkland Islands (Malvinas), Grenada, Montserrat, Saint Kitts and Nevis, Saint Lucia, Saint Pierre and Miquelon, Saint Vincent and Grenadines, Saint Maarten (Dutch part), Turks and Caicos Islands.

[5] The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD and/or the IEA is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

[6] Individual data are not available and are estimated in aggregate for: Burkina Faso, Burundi, Cabo Verde, Central African Republic, Chad, Comoros, Djibouti, Gambia, Guinea, Guinea-Bissau, Lesotho, Liberia, Malawi, Mali, Mauritania, Sao Tome and Principe, Seychelles, Sierra Leone and Somalia.

Fossil fuel supply regions

As noted in the model description, the fossil fuel supply modules have a different regional breakdown relative to the regions used in the rest of the GEC Model. This enables the supply modules in order to most accurately reflect the particularities of fossil fuel producing countries and regions. The regional breakdown for these modules are as follows:

Oil and natural gas supply module regions

The *GEC Model* oil and natural gas supply module consists of 113 regions, of which 102 countries are modelled on an individual basis. Trade volumes broken downy by pipeline and liquefied natural gas are modelled for the following 20 regions: Canada, Mexico, United States, Brazil, Other Central and South America, European Union, Other Europe, Other transition economies in Europe, North Africa, West Africa, East Africa, Russia, Caspian, Middle East, Japan and Korea, Australia and New Zealand, China, India, Southeast Asia, and Other Asia Pacific. The 102 countries modelled individually in the oil and natural gas module are categorised into the 20 natural gas trade regions in the following manner:

Canada: Canada.

Mexico: Mexico.

United States: United States.

Brazil: Brazil.

Other Central and South America: Argentina, Bolivia, Chile, Colombia, Cuba, Ecuador, Guyana, Paraguay, Peru, Trinidad and Tobago, Uruguay, and Venezuela.

European Union: Denmark, Estonia, France, Germany, Italy, Netherlands, Poland, Romania, Slovenia, and Sweden.

Other Europe: Greenland, Israel, Norway, and the United Kingdom.

Other transition economies in Europe: Ukraine.

North Africa: Algeria, Libya, Egypt, Tunisia, and Morocco.

West Africa: Angola, Benin, Cameroon, Central African Republic, Chad, Congo, Democratic Republic of Congo, Equatorial Guinea, Gabon, Gambia, Ghana, Guinea, Guinea Bissau, Ivory Coast, Liberia, Mauritania, Niger, Nigeria, Senegal, Sierra Leone, and Togo.

East Africa: Botswana, Eritrea, Ethiopia, Kenya, Madagascar, Mozambique, Namibia, Seychelles, Somalia, South Africa, South Sudan, Sudan, Tanzania, and Uganda.

Russia: Russia.

Caspian: Azerbaijan, Kazakhstan, Turkmenistan, and Uzbekistan.

Middle East: Bahrain, Iran, Iraq, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syria, United Arab Emirates, and Yemen. Data for Saudi Arabia and Kuwait include 50% each of production from the Neutral Zone.

Japan and Korea: Japan and Korea.

Australia and New Zealand: Australia and New Zealand.

China: China.

India: India.

Southeast Asia: Brunei Darussalam, Indonesia, Malaysia, Philippines, Thailand, and Viet Nam.

Other Asia Pacific: Bangladesh and Pakistan.

Coal supply module regions

19 countries are modelled on an individual basis in the GEC Model coal supply module: Australia, Brazil, Canada, Chile, China, Colombia, India, Indonesia, Japan, Korea, Mexico, Mongolia, Mozambique, New Zealand, Russia, South Africa, the United States, Venezuela and Viet Nam.

Acronyms

ACEA	European Automobile Manufacturers' Association
AC	alternating current
AFOLU	agriculture, forestry and other land use
AIM	Aviation Integrated Model
APS	Announced Pledges Scenario
ASEAN	Association of Southeast Asian Nations
ASIF	activity, structure, intensity and fuel use
ATJ	alcohol-to-jet
BECCS	bioenergy equipped with CCUS
BEV	battery electric vehicles
CAPEX	capital expenditure
CBM	coalbed methane
CCGT	combined-cycle gas turbine
CCUS	carbon capture, utilisation and storage
CDR	carbon dioxide removal
CH_4	methane

CHP	combined heat and power; the term co-generation is sometimes used
CO	carbon monoxide
CO_2	carbon dioxide
CO_2-eq	carbon-dioxide equivalent
CSP	concentrating solar power
CTG	coal-to-gas
CTL	coal-to-liquids
DAC	direct air capture
DACU	direct air capture and utilisation
DACS	direct air capture and storage
DC	direct current
DRI	direct reduced iron
DSI	demand-side integration
DSO	distribution system operator
DSR	demand-side response
EAF	electric arc furnace
EHOB	extra-heavy oil and bitumen
EOR	enhanced oil recovery
EPC	Engineering, procurement and construction
ESG	environmental, social and governance
ETP	Energy Technology Perspectives
ETSAP	Energy Technology Systems Analysis Program
EU	European Union
EU ETS	European Union Emissions Trading System
EV	electric vehicle
EVSE	Electric vehicle supply equipment
FAME	fatty acid methyl ester
FAO	Food and Agriculture Organization of the United Nations
FCEV	fuel cell electric vehicle
FDI	foreign direct investment
FTE	Full-time employment
GAINS	Greenhouse Gas - Air Pollution Interactions and Synergies
GDP	gross domestic product
GEC Model	Global Energy and Climate Model
GHG	greenhouse gases
GIMF Model	Global Integrated Monetary and Fiscal Model
GIS	Geographic Information System
GLOBIOM	Global Biosphere Management Model
GTL	gas-to-liquids
H_2	hydrogen
HEFA	hydrogenated esters and fatty acids
HFO	heavy fuel oil
HRS	hydrogen refuelling stations
HSR	high-speed rail
HVO	hydrotreated vegetable oil
IAEA	International Atomic Energy Agency
ICE	internal combustion engine
ICS	improved biomass cookstoves
IEA	International Energy Agency
IGCC	integrated gasification combined-cycle

IIASA	International Institute for Applied Systems Analysis
ILO	International Labour Organization
IMF	International Monetary Fund
IMO	International Maritime Organization
IPCC	Intergovernmental Panel on Climate Change
IRENA	International Renewable Energy Agency
ISCED	International Standard Classification of Education
ISIC	International Standard Industrial Classification
ISO	International Organization for Standardization
JRC	Joint Research Centre
LCOE	levelised cost of electricity
LCV	light commercial vehicle
LDV	light-duty vehicle
LED	light-emitting diode
LMDI	logarithmic mean divisia index
LNG	liquefied natural gas
LPG	liquefied petroleum gas
LRMC	Long-run marginal cost
LULUCF	land use, land-use change and forestry
MAGICC	Model for the Assessment of Greenhouse Gas Induced Climate Change
MoMo	Mobility Model
MTOMR	Medium-Term Oil Market Report
NAICS	North American Industry Classification System
NACE	European Nomenclature of Economic Activities
NDCs	Nationally Determined Contributions
NEA	Nuclear Energy Agency
NGLs	natural gas liquids
NGV	natural gas vehicle
NH_3	ammonia
NO_X	nitrogen oxides
N_2O	nitrous oxide
NZE	Net Zero Emissions by 2050 Scenario
O&M	Operations and maintenance
OECD	Organisation for Economic Co-operation and Development
OnSSET	Open Source Spatial Electrification Tool
OPEC	Organization of the Petroleum Exporting Countries
OPEX	operational expenditure
PEM	polymer electrolyte membrane or proton exchange membrane
PLDV	passenger light-duty vehicle
PM	particulate matter
$PM_{2.5}$	fine particulate matter
PPA	power purchase agreement
PPP	public-private partnership
PV	photovoltaic
SDG	Sustainable Development Goal
SDS	Sustainable Development Scenario
SMR	steam methane reformation
SO_2	sulphur dioxide
SOEC	Solid oxide electrolyser cells
STEPS	Stated Policies Scenario

SUVs	Sport utility vehicles
SVO	Straight vegetable oil
T&D	transmission and distribution
TCP	Technology Collaboration Programme
TES	total energy supply
TFC	total final consumption
TFEC	total final energy consumption
TIMES Model	The Integrated MARKAL-EFOM System Model
TRL	technology readiness level
TSO	transmission system operator
UCL	University College London
UN	United Nations
UNIDO	United Nations Industrial Development Organization
US	United States
USGS	United States Geological Survey
VALCOE	value-adjusted levelised cost of electricity
VRE	variable renewable energy
WACC	weighted average cost of capital
WEM	World Energy Model
WEO	World Energy Outlook
WHO	World Health Organization
ZEV	zero-emission vehicle
ZCRB	zero-carbon-ready building

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