Power Systems Transformation:

Delivering Competitive, Resilient Electricity in High-Renewable Systems

July 2025 | Version 1.0

Energy
Transitions
Commission

The Energy Transitions Commission (ETC) is a global coalition of leaders from across the energy landscape committed to achieving net-zero emissions by mid-century, in line with the Paris climate objective of limiting global warming to well below 2°C and ideally to 1.5°C.

Our Commissioners come from a range of organisations – energy producers, energy-intensive industries, technology providers, finance players and environmental NGOs – which operate across developed and developing countries and play different roles in the energy transition. This diversity of viewpoints informs our work: our analyses are developed with a systems perspective through extensive exchanges with experts and practitioners. The ETC is chaired by Lord Adair Turner who works with the ETC team, led by Ita Kettleborough (Director), and Mike Hemsley (Deputy Director).

The ETC's *Power Systems Transformation: Delivering Competitive, Resilient Electricity in High-Renewable Systems* report briefing was developed in consultation with ETC Members, but it should not be taken as members agreeing with every finding or recommendation. The ETC team would like to thank the ETC members, member experts and the ETC's broader network of external experts for their active participation in the development of this report.

This report is accompanied with a supplementary Insights briefing, *Connecting the World: Long-Distance Transmission as a Key Enabler of a Zero-Carbon Economy,* which focuses on the potential for long-distance transmission in high variable renewable power systems and identifies leading global opportunities.

The ETC Commissioners not only agree on the importance of reaching net-zero carbon emissions from the energy and industrial systems by mid-century but also share a broad vision of how the transition can be achieved. The fact that this agreement is possible between leaders from companies and organisations with different perspectives on and interests in the energy system should give decision-makers across the world confidence that it is possible simultaneously to grow the global economy and to limit global warming to well below 2°C. Many of the key actions to achieve these goals are clear and can be pursued without delay.

This report should be cited as: ETC (2025), *Power Systems Transformation: Delivering Competitive, Resilient Electricity in High-Renewable Systems.*

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Major ETC reports and working papers

To download all ETC reports, papers, explainers and factsheets visit www.energy-transitions.org

Global Reports

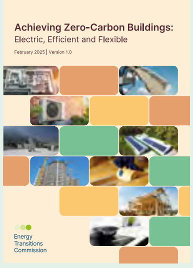
Mission Possible (2018) outlines pathways to reach net-zero emissions from the harder-to-abate sectors in heavy industry (cement, steel, plastics) and heavy-duty transport (trucking, shipping, aviation).

Making Mission Possible (2020) shows that a net-zero global economy is technically and economically possible by mid-century and will require a profound transformation of the global energy system.

Making Mission Possible Series (2021-2022) outlines how to scale up clean energy provision to achieve a net-zero emissions economy by mid-century.

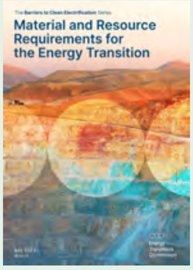
Barriers to Clean Electrification Series (2022-2025) recommends actions to overcome key obstacles to clean electrification scale-up, including planning and permitting, supply chains and power grids.

Financing the Transition (2023–2024) quantifies the finance needed to achieve a net-zero global economy and identifies policies needed to unleash investment on the scale required.



Achieving Zero-Carbon Buildings (2025) draws a complete picture of the buildings sector’s emissions and energy use and describes how a combination of electric, efficient, and flexible solutions can decarbonise buildings, improve standards of living, and reduce energy bills if supported by ambitious policy.

COP-focused



Material and Resource Requirements for the Energy Transition (2023) dives into the natural resources and materials required to meet the needs of the transition by mid-century, and recommends actions to expand supply rapidly and sustainably.

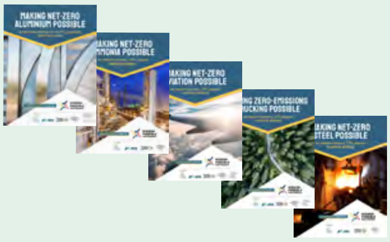
Fossil Fuels in Transition (2023) describes the technically and economically feasible phase-down of coal, oil and gas that is required to limit global warming to well below 2°C as outlined in the Paris Agreement.

Nationally Determined Contributions (2024) calls for industry and government collaboration to raise ambition in the next round of Nationally Determined Contributions by COP30 to limit the impact of climate change.

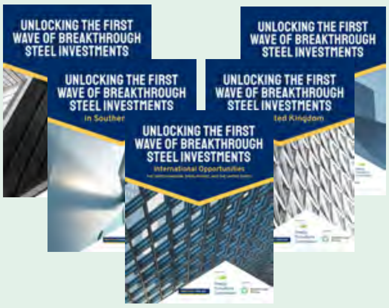
Sectoral and cross-sectoral focuses

Sectoral focuses provided detailed decarbonisation analyses on six of the harder-to-abate sectors after the publication of the **Mission Possible** report (2019).

As a core partner of the MPP, the ETC also completes analysis to support a range of sectorial decarbonisation initiatives:

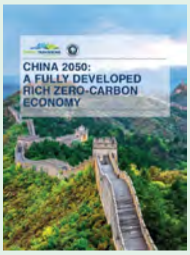


MPP Sector Transition Strategies (2022-2023) a series of reports that guide the decarbonisation of seven of the hardest-to-abate sectors. Of these, four are from the materials industries: aluminium, chemicals, concrete, and steel, and three are from the mobility and transport sectors – aviation, shipping, and trucking.



Unlocking the First Wave of Breakthrough Steel Investments (2023) This ETC series of reports looks at how to scale up near-zero emissions primary (ore-based) steelmaking this decade within specific regional contexts: the UK, Southern Europe, France and USA.

Regional Focus



China 2050: A Fully Developed Rich Zero-carbon Economy (2019) Analyses China's energy sources, technologies and policy interventions required to reach net-zero carbon emissions by 2050.

A series of reports on the Indian power system, outlining decarbonisation roadmaps for India's electricity supply and heavy industry.

Canada's Building Heating Decarbonization - Jurisdictional Scan (2024) provides an in-depth look at how governments across Canada and the globe are using policy to transition building heating away from fossil fuels.

Setting up industrial regions for net zero (2021-2023) explore the state of play in Australia, and identifies opportunities for transitioning to net-zero emissions in five hard-to-abate supply chains.

Pathways to Net-Zero for the US Energy Transition (2022-2023) examines the trendlines, challenges, and opportunities for meeting the US net-zero objective.

A Path Across the Rift (2023) reviews an analysis of African energy transitions and pinpoints critical questions we need to answer to foster science-based policymaking to enable decisions informed by clear and objective country-specific analysis.

Glossary

Accelerated but Clearly Feasible Scenario (ACF Scenario): A decarbonisation scenario defined by the ETC that assumes rapid but technically and economically feasible action to achieve net-zero emissions.

Ancillary services: Specialised functions that help maintain grid stability and reliability, essential for ensuring the uninterrupted supply of electricity. These services include frequency regulation, voltage control, reserves and black start capabilities.

Balancing Services Use of System (BSUoS): A UK-specific charge applied to electricity suppliers and generators to recover the cost of balancing the electricity system. It is administered by the National Grid Energy System Operator (NESO), which is responsible for ensuring that supply and demand are matched in real time.

Battery Energy Storage System (BESS): A system that stores electricity in batteries for later use.

Black start (for energy storage): The ability of an energy storage system to restart parts of the power grid independently after a total or partial shutdown, without relying on external power sources. This supports grid restoration by energising key infrastructure and enabling other generators to reconnect.

Blue hydrogen: Hydrogen produced from natural gas via steam methane reforming or autothermal reforming, with the resulting CO_2 emissions captured and stored using CCUS technologies. It is considered a low-carbon hydrogen pathway but relies on effective and sustained high capture rates to achieve substantial emissions reductions.

Compressed Air Energy Storage (CAES): A long-duration energy storage technology that stores energy by compressing air and injecting it into underground caverns or pressure vessels during periods of excess electricity supply. When electricity is needed, the compressed air is released, heated, and expanded through a turbine to generate power.

Capital Expenditure (CAPEX): The upfront cost of constructing or installing a piece of infrastructure or equipment.

Carbon Capture and Use or Carbon Capture and Storage (CCUS or CCS): The term "carbon capture" refers to the process of capturing CO_2 on the back of energy and industrial processes. Unless specified otherwise, we do not include direct air capture (DAC) when using this term. The term Carbon Capture and Storage refers to the combination of carbon capture with underground carbon storage while Carbon Capture and Use refers to the use of carbon in carbon-based products in which CO_2 is sequestered over the long term (e.g., in concrete, aggregates, carbon fibre). Carbon-based products that only delay emissions in the short-term (e.g., synfuels) are excluded when using this terminology.

Carbon emissions/CO_2 emissions: We use these terms interchangeably to describe anthropogenic emissions of carbon dioxide in the atmosphere.

Carbon price: A government-imposed pricing mechanism – the two main types being either a tax on products and services based on their carbon intensity, or a quota system setting a cap on permissible emissions in the country or region and allowing companies to trade the right to emit carbon (i.e. as allowances). This should be distinguished from some companies' use of what are sometimes called "internal" or "shadow" carbon prices, which are not prices or levies, but individual project screening values.

Clean electrification: The substitution of electricity for fossil fuels in end-uses such as transport, buildings, and industry, combined with the decarbonisation of electricity generation.

Combined Cycle Gas Turbine (CCGT): A gas turbine-based power generation technology that uses both a gas turbine and a steam turbine in sequence to increase efficiency.

Consumer Price Index (CPI): A measure of the average change in prices paid by consumers over time for goods and services.

Contract for Difference (CfD): A government policy instrument that guarantees a fixed price for electricity generation, paying the difference if market prices fall below that level.

Cost of capital: A measure of the risk associated with investments; it expresses the expected financial return, or the minimum required rate, for investing in a company or a project.

Direct Air Capture (DAC or DACC): DAC technologies extract CO_2 directly from the atmosphere at any location, unlike carbon capture which is generally carried out at the point of emissions, such as a steel plant. The CO_2 can be permanently stored in deep geological formations or used for a variety of applications.

Demand side flexibility (DSF): The ability to shift the consumption of electricity at peak times (e.g., through "smart charging" an EV, or time-shifting usage of other electricity use), offsetting new grid and generation capacity needed across the system.

Distribution High Voltage (DHV): High-voltage networks within the distribution system, typically between 33 kV and 132 kV.

Distribution Low Voltage (DLV): The part of the electricity network that delivers power at low voltages to end users.

Distribution Medium Voltage (DMV): Networks that operate at medium voltage levels, typically between 1 kV and 33 kV.

Distribution Use of System (DUoS): Charges levied to recover the cost of operating and maintaining distribution networks.

Dynamic Line Rating (DLR): A grid management technology that adjusts the thermal limits of transmission lines in real time, based on weather and loading conditions.

Engineering, Procurement and Construction (EPC): A common project delivery model in infrastructure whereby one contractor delivers all aspects of design, procurement and construction. This report discusses EPC in terms of costs and how that contributes to total storage costs.

Flexible AC Transmission Systems (FACTS): Technologies that enhance the controllability and power transfer capability of AC transmission networks.

Flexible Dispatchable Generation: Generation that can rapidly ramp up/down to match variable supply or demand

Frequency response (for energy storage): The ability of an energy storage system to inject or absorb power to help stabilise grid frequency following imbalances between supply and demand. This includes rapid actions such as fast frequency response (within 1 second) as well as slower responses over tens of seconds to minutes, depending on system needs and market design.

Grid-Forming Inverter: An inverter that sets and regulates grid voltage and frequency, allowing stable operation even in the absence of synchronous generation.

Greenhouse gases (GHGs): Gases that trap heat in the atmosphere. Global GHG emission contributions by gas include CO_2 (76%), methane (16%), nitrous oxide (6%) and fluorinated gases (2%).

Green hydrogen: Refers to fuels produced using electricity from low-carbon sources (i.e. variable renewables such as wind and solar).

Indirect use of fossil fuels: The use of fossil fuels to generate electricity.

Levelised cost of electricity (LCOE): A measure of the average net present cost of electricity generation for a generating plant over its lifetime. The LCOE is calculated as the ratio between all the discounted costs over the lifetime of an electricity-generating plant divided by a discounted sum of the actual energy amounts delivered.

Levelised Cost of Storage (LCOS): The total discounted cost of building and operating a storage facility over its lifetime, divided by the total volume of electricity discharged (discounted).

Locational Marginal Pricing (LMP): A market mechanism in which electricity prices vary by location, reflecting local supply, demand, and network constraints.

Long-distance transmission: Transmission of electricity over hundreds to thousands of kilometres, typically using HVDC.

Medium-long duration storage: Energy storage systems designed to discharge over 8 to 50 hours.

Merit Order Effect (MOE): The reduction in wholesale electricity prices as low marginal cost renewables displace more expensive generation in the merit order.

National Energy System Operator (NESO): A UK-wide independent system operator responsible for planning and operating the electricity system.

Open Cycle Gas Turbine (OCGT): A gas turbine power plant that operates without a steam cycle, offering fast ramping but lower efficiency.

Operational Expenditures (OPEX): Ongoing costs associated with the operation and maintenance of an asset or system.

Peak Load: The highest electricity demand observed over a given time period.

Power Conversion System (PCS): Equipment used to convert electrical power from one form to another, such as from DC to AC.

Possible but Stretching Scenario (PBS Scenario): A more ambitious decarbonisation scenario that assumes aggressive policy support and faster-than-expected technological progress.

Power Flow Controller (PFC): Equipment used to regulate power flows on transmission networks by controlling voltage, impedance, or phase angle.

Power-to-X: Broad term for converting electricity into other energy carriers or products (e.g., hydrogen, fuels)

Pumped Storage Hydropower: A method of storing energy by pumping water uphill to a reservoir

Purchasing Power Agreement (PPA): A long-term contract between an electricity generator and a buyer, guaranteeing a price for the electricity produced.

Scope 2 emissions: Emissions that a company causes indirectly and come from where the energy it purchases and uses is produced. For example, emissions caused when generating the electricity used in the company's office buildings.

Short-duration storage: Storage technologies designed to balance electricity supply and demand over timescales of up to 8 hours, typically batteries.

Static Synchronous Compensators (STATCOMs): Power electronic devices that regulate voltage and improve power quality in transmission networks.

Static VAR Compensators (SVCs): Systems used to provide fast-acting reactive power compensation to maintain voltage stability.

Synchronous Condenser: A rotating machine providing inertia and voltage support without generating power.

Thermal Energy Storage: A method of storing energy as heat, for later conversion or direct use.

Transmission Network Use of System (TNUoS): A UK-specific charge applied to electricity generators and suppliers to recover the cost of building and maintaining the high-voltage transmission system. These charges are levied by the National Grid Electricity Transmission (NGET) as the transmission owner, with cost recovery administered through the Electricity System Operator.

Transmission System Operator (TSO): An entity responsible for operating and maintaining the high-voltage transmission network.

Ultra-long duration storage: Storage systems that discharge over durations longer than 50 hours

Value-Added Tax (VAT): A consumption tax levied on goods and services.

Variable Renewable Electricity (VRE): Electricity generated from renewable sources whose output varies with natural conditions, such as solar and wind.

Vehicle-to-Grid (V2G): A system in which EVs can return stored electricity to the grid during peak demand periods.

Wholesale cost of power / wholesale electricity price: The price paid by electricity suppliers or large buyers to purchase electricity in bulk from generators through wholesale electricity markets.
It reflects the cost of producing electricity and varies with factors such as fuel prices, supply and demand, weather, and system constraints. This cost typically excludes network, retail, and policy-related charges passed on to end consumers.

Contents

Introduction

Clean electrification, driven by the decarbonisation of power systems and the substitution of electricity for fossil fuels in industry, transport, and buildings, is the foundation of the transition to a global net-zero economy. In many sectors, direct electrification will be the most cost-effective route to decarbonisation; in others, hydrogen produced via electrolysis is likely to play a significant role.

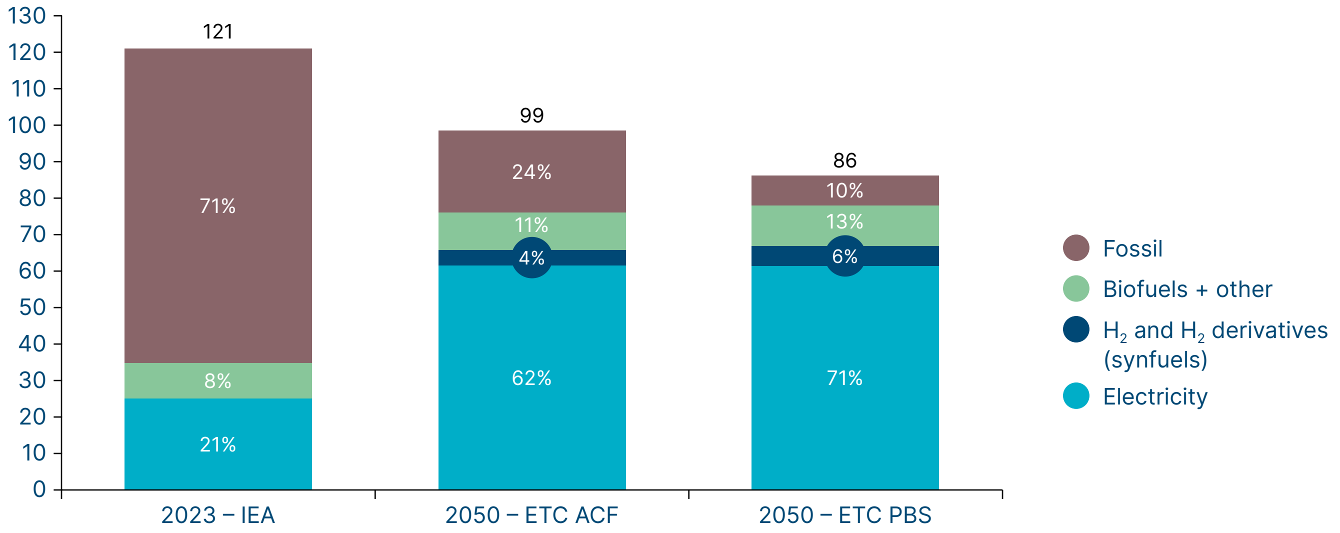
As a result, total electricity demand will grow dramatically. The ETC's latest updates to the two net-zero scenarios, Accelerated by Clearly Feasible (ACF) and Possible but Stretching (PBS), initially published in December 2023, suggest that the share of direct electricity usage could increase from 21% of final energy demand today to 62–71% by mid-century [Exhibit 0.1].[1] Total global electricity demand could potentially reach around 90,000 TWh by 2050, compared to 30,000 TWh today.[2]

Exhibit 0.1

Electricity's share of final energy demand triples in net zero scenarios

Final energy demand scenario comparison

Thousand TWh



NOTE: 2050 scenarios based on the 2025 updates to the Accelerated but Clearly Feasible (ACF) and Possible but Stretching (PBS) scenarios.

SOURCE: Systemiq analysis for the ETC; IEA (2024), *World Energy Outlook 2024*.

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[1] ETC (2023), *Fossil Fuels in Transition: Committing to the phase-down of all fossil fuels.*

[2] ETC (2021), *Making Clean Electrification Possible: 30 Years to Electrify the Global Economy.*

Clean electricity could be delivered in several ways. Many countries have large hydropower resources, and both nuclear power and geothermal resources could play a role in providing continuous zero-carbon power. The ETC is currently conducting detailed analysis of the potential role of nuclear and geothermal, to be published in 2026. However, in many parts of the world, the dominant sources of zero-carbon power are likely to be wind and solar. Many estimates of cost-effective power decarbonisation systems project that the share of wind and solar electricity (VRE) in total power supply will reach 70% or even higher.[3]

This reflects the dramatic reductions in the cost of solar PV over the last 10 years, and the less dramatic but still significant fall in wind power generation costs.[4] In many parts of the world, the cheapest way to produce a kWh of electricity is from wind or solar resources, and this cost advantage compared to fossil fuels will widen in future.[5,6]

The crucial challenge is what to do when the sun does not shine and the wind does not blow, and how to balance electricity supply against demand across days, weeks, months, and years. This can be achieved in different ways, including via the use of multiple energy storage technologies, by encouraging increased flexibility in the timing of electricity use (known as demand side flexibility (DSF)), or by increased transmission connections between regions and countries. Although complex to achieve, long-distance connections can be particularly beneficial where feasible to reach agreement, as it can allow cost effective balancing across different weather systems. Implementing some of these balancing options will add costs to total system operation.

Rapidly increasing electricity demand also requires large-scale expansion and the operational optimisation of both transmission and distribution grids. In addition, the shape of grids will need to change significantly, for instance, to connect wind and solar resources far from demand centres, and to accommodate large-scale decentralised generation (in particular, rooftop solar). These changes will often impose significant cost, but these costs can be reduced by the application of multiple innovative grid technologies (IGTs).

This report therefore analyses how electricity systems will need to adjust to accommodate rising electricity demand and high shares of renewables. Our analysis and conclusions are set out in the following four chapters:

1. **Managing the system balancing challenge.** It is technically and economically possible to manage system balancing challenges in systems with very high (e.g., 80%+) wind and solar penetration, delivering round-the-clock electricity at costs below those of today's fossil fuel-based systems. The lowest total system costs will be seen in sun belt countries with large solar resources and primarily short duration balancing needs. Costs will be higher in high latitude countries, which are primarily dependent on wind resources and have significant seasonal balancing requirements. The exception are countries with significant hydro resources which can be used for cost effective balancing.
2. **Managing grid expansion to minimise grid cost per kWh.** Grids are a central enabler of electrification and clean energy development, and will need significant expansion in the next decade. However, this needs to be done in a cost effective manner. Global required annual grid investments could grow from $370 billion in 2024 to around $850 billion in the 2030s and 2040s. These costs could be reduced by up to 35% through the application of multiple innovative grid technologies (IGTs). Maximising demand side flexibility also represents a particularly low-cost opportunity. While total grid investment will rise, the expanded grid capacity will support significantly higher electricity demand. What matters for consumers is the cost per kWh and by 2050, this is expected to be at or below today's levels.
3. **System generation and grid costs in the long term and in transition.** In the long term, total system wholesale generation, balancing and grid costs per kWh in power systems with high wind and solar shares could be significantly below the cost of today's fossil fuel-based systems by lowering displacing more expensive generation. Costs in low latitude/sunny countries, Mediterranean climates, and in China are likely to be lower than today's costs due to the low cost of solar generation and short-duration balancing. Costs could also be somewhat lower in high latitude countries, which will depend primarily on wind resources. It is vital to also focus on cost during the transition, particularly in high latitude countries that are currently dependent on expensive gas supply. Speeding up the transition to future lower-cost systems will require careful policy design in order to balance short-term cost trade-offs.
4. **Key enablers for cost-effective power system development.** To achieve the potential low costs of much larger electricity systems, primarily dependent on variable wind and solar resources, requires a combination of strategic vision, optimal power market design and grid company regulation, the application of new grid management technologies, actions to overcome potential supply chain constraints, and key forms of customer engagement.

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[3] IEA (2021), *Net Zero by 2050: A Roadmap for the Global Energy Sector*; IRENA (2023), *World Energy Transitions Outlook 2023*.

[4] IRENA (2023), *Renewable Power Generation Costs in 2022*.

[5] Lazard (2023), *Levelized Cost of Energy Analysis – Version 16.0*; BNEF (2023), *New Energy Outlook*.

[6] Way et al. (2023), *Empirically grounded technology forecasts and the energy transition*.

1

Managing the system balancing challenge

The Energy Transitions Commission has emphasised in several reports that achieving a zero-carbon global economy requires extensive clean electrification.[7] This will require increasing global electricity consumption two to three times by 2050, with further significant growth thereafter, and ensuring that electricity generation produces minimal or zero emissions. Such a transformation can be both feasible and cost-effective – including transitioning to power systems where 70% to 90% of generation comes from variable renewable sources such as wind and solar.[8] The following sections explain how, with five key messages:

- While hydropower, nuclear and geothermal will play significant roles in many clean power systems, and while there will remain a role for thermal dispatchable power plants, wind and solar are likely to be cost-competitive generation sources in most countries and will account for the vast majority of future new capacity.
- As the share of variable renewables rises, power systems will need to balance energy supply and demand across days, weeks, months and years. The severity and the specific nature of this challenge varies by country/region. In particular, there is a significant difference between the balancing challenge in low latitude sun belt countries and in high latitude wind belt countries.
- The balancing challenge can be addressed using a range of available technologies and business models, including flexible dispatchable generation, innovative grid technologies, long-distance interconnection, energy storage solutions such as batteries or pumped hydro, and demand-side flexibility. Different solutions are best suited to different timescales, and a key question is how long the economically viable duration of lithium-ion batteries can extend to, given the significant reductions in battery costs in recent years.
- Balancing costs tend to rise with the duration over which balancing is required and are therefore higher in countries with longer-duration needs, typically wind belt countries. However, in the majority of countries there are viable and cost-effective solutions for balancing power systems with high shares of wind and solar.
- In low latitude sun belt countries with large solar resources and lower seasonal balancing needs, total system electricity system costs, including both generation and balancing, will be lower, and in some cases significantly lower, than in today's fossil fuel-based systems. In high latitude countries primarily reliant on wind generation, costs will be higher than in the sun belt countries but are likely to be at or slightly below today's levels.

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[7] ETC (2021), *Making Clean Electrification Possible: 30 Years to Electrify the Global Economy;* ETC (2021), *Making Mission Possible: Delivering a Net-Zero Economy;* ETC (2023), *Fossil Fuels in Transition: Committing to the phase-down of all fossil fuels.*

[8] ETC (2021), *Making Clean Electrification Possible: 30 Years to Electrify the Global Economy.*

1.1 Solar and wind will be the primary source of power generation in the future

Over the past decade, the share of variable renewable electricity in global power systems has grown significantly. In 2023, as shown in Exhibit 1.1 below, countries such as Germany, Ireland, Spain, Uruguay, Denmark, and Portugal generated over 40% of their electricity from wind and solar, with Denmark leading the group with nearly 70% of electricity generation from wind and solar.[9,10]

Solar Photovoltaic (PV) deployment has soared, with global annual installations reaching around 600 GW in 2024, driven by rapid growth in China.[11] This expansion has continually outpaced successive International Energy Agency (IEA) projections, as shown in Exhibit 1.2 below and is far more rapid than the ETC envisaged in the 2021 report *Making Clean Electrification Possible*. Similarly, between 2014 and 2024, global wind power capacity experienced substantial growth. In 2014, the cumulative installed wind capacity was approximately 370 GW and by the end of 2024 this capacity had surpassed 1,135 GW.[12]

This rapid growth of wind and solar has been driven by faster than expected cost reduction. Since 2010, solar and wind levelised cost of electricity (LCOE) has declined by 92% and 70% respectively[13], as shown in Exhibit 1.3 below. This has largely been driven by the CAPEX costs for fixed-axis PV systems falling by 82%[14] since 2010, while wind turbine costs have fallen by 68% for onshore wind and 59% for offshore wind[15] in real terms since 2010. In China, we have seen reductions of 83% and 79% in solar and wind CAPEX costs from 2014 to 2024.[16] Together with installation and other cost reductions, this has driven rapid reductions in the LCOE and contract prices for solar and wind supply.

These cost reductions have now made unsubsidised solar and wind competitive sources of power generation in many countries. Reasonable projections of future cost levels suggest that this advantage will continue to grow in the future, with solar becoming the cheapest way to produce a (non-firm) kWh of electricity in almost all countries compared to traditional fossil fuel generation.[17]

The cost competitiveness of solar and wind energy does not exclude significant roles for other low-carbon generation options. Conventional hydropower remains highly cost-competitive in many regions and continues to provide substantial shares of electricity generation in countries like Norway and Brazil. In Brazil, for instance, hydropower contributed to 56% of the nation's total electricity generation in 2024.[18]

The ETC also believes that existing nuclear plant lives should be extended for as long as possible, due to their very low marginal cost of operation. The exception to this would be nuclear plants that do not meet up to date industry safety standards e.g., plants without passive safety features.[19] New nuclear developments in certain geographies, regardless of whether large fission plants or small modular reactors, face current economic and technological challenges, including high capital costs and long construction timelines. For conventional fission plants, there is the additional risk of significant schedule overruns. However, new nuclear development costs might reduce over time and present opportunities for supplying low-carbon, baseload energy to large demand sources such as data centres. Additionally, there is growing interest in developing various forms of geothermal energy supply as a complementary low-carbon resource. The ETC is currently analysing the potential roles of nuclear and geothermal sources in global power systems, with a report expected in early 2026.

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[9] Ember (2025), *Electricity generation – Wind and solar*. Available at https://ember-energy.org/data/electricity-data-explorer/. [Accessed March 2025].

[10] It is important to note that it is relatively easy for small countries to achieve high wind and solar shares if they are interconnected with large countries. But the growth of wind and solar shares across multiple interconnected countries (e.g., Spain and Portugal, and Germany and Denmark) illustrates high wind and solar penetration is possible across wide geographic areas.

[11] IEA (2024), *Snapshot of Global PV Markets*.

[12] GWEC (2025), *Wind industry installs record capacity in 2024 despite policy instability*.

[13] BNEF (2025), *Levelized Cost of Electricity Update 2025*.

[14] NREL (2021), *Documenting a Decade of Cost Declines for PV Systems*. Available at: https://www.nrel.gov/news/program/2021/documenting-a-decade-of-cost-declines-for-pv-systems.html. [Accessed February 2025].

[15] Harvard Business Review (2024), *The Long-Term Costs of Wind Turbines*. Available at: https://hbr.org/2024/02/the-long-term-costs-of-wind-turbines. [Accessed February 2025].

[16] BloombergNEF (2025), *Levelized Cost of Electricity Update 2025: Charts and Data*.

[17] BNEF (2025), *New Energy Outlook (NEO) Capacity and Generation Forecast*.

[18] Ember (2025), *Brazil: Power sector overview*. Available at https://ember-energy.org/countries-and-regions/brazil/. [Accessed March 2025].

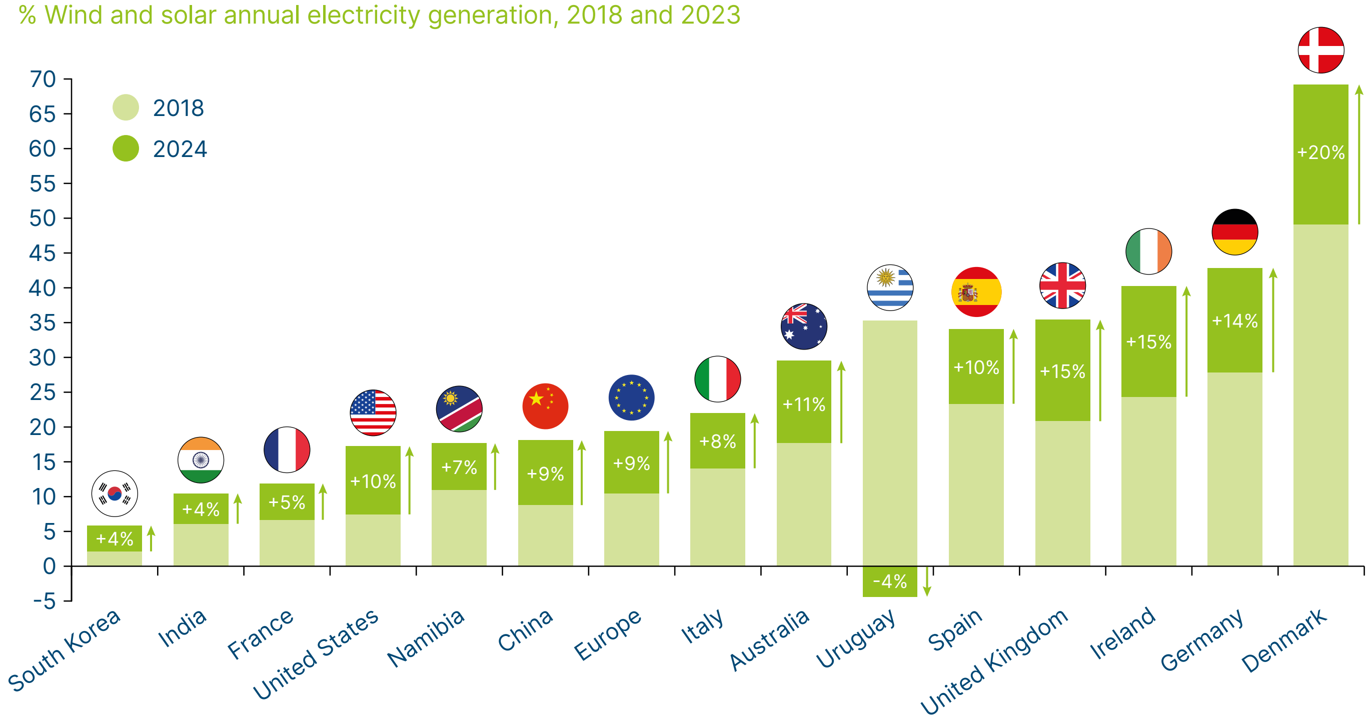
[19] ETC (2023), *Building Energy Security: Addressing Risks and Building Resilience in a Decarbonised Energy System*.

Exhibit 1.1

Share of wind and solar generation has increased significantly in selected markets

Annual wind and solar share in selected countries

% Wind and solar annual electricity generation, 2018 and 2023



NOTE: France's wind and solar share dropped from 14% in 2023 to 12% in 2024 due to increased nuclear and hydro contributions to the electricity generation mix in 2024.

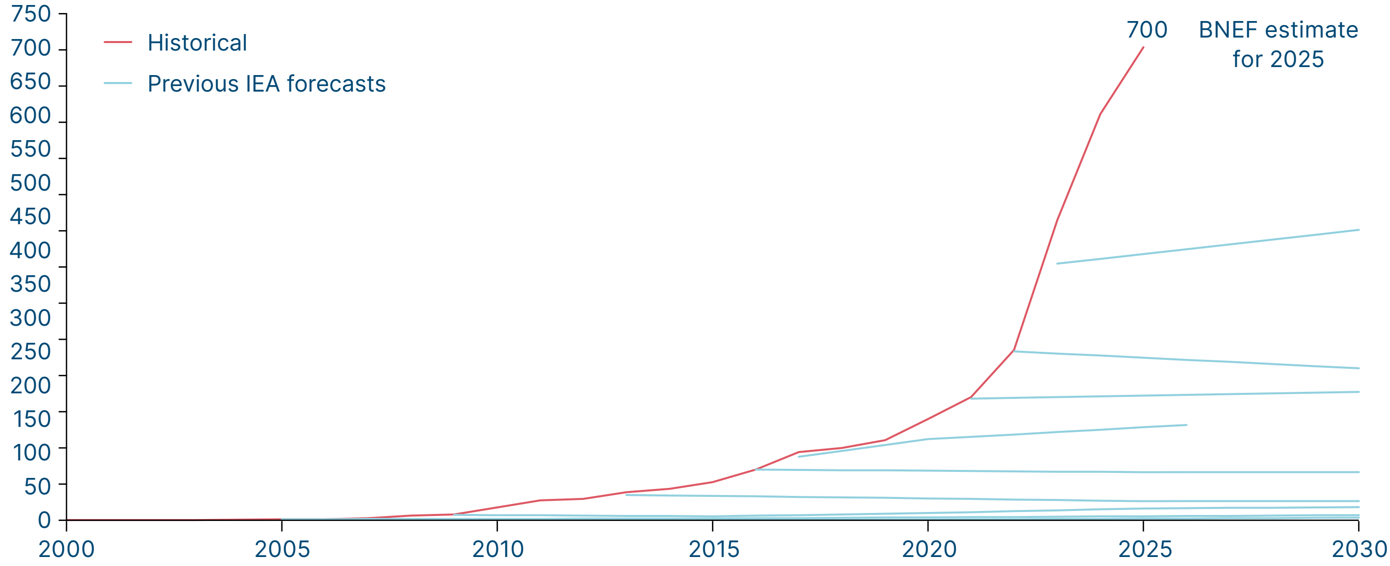
SOURCE: Ember (2024), *Electricity Data Explorer,* available at https://ember-energy.org/data/electricity-data-explorer/. [Accessed January 2025].

Exhibit 1.2

Annual solar PV installations continuously beating expectations

Annual global solar PV installations compared to IEA forecasts

GW



NOTE: Capacity figures are presented in direct current (DC) terms. The IEA standardises PV capacity data to DC for consistency across countries, converting figures from alternating current (AC) where necessary. BNEF also reports PV capacity in DC terms, facilitating direct comparison between the two sources.

SOURCE: Systemiq analysis for the ETC; BNEF (2025), *BNEF Solar Forecasts;* IEA (2024), *World Energy Outlook.*

Despite these alternatives, wind and solar are highly likely to play a dominant role in power systems. Reasonable scenarios from various bodies suggest that by 2050, the share of wind and solar generation could be as high as 82% in the UK,[20] 62% in China[21,22] and 95% in India [Exhibit 1.4].[23] In Indonesia, analysis by ETC member, Institute for Essential Services Reform (IESR), has suggested that solar resources could in principle produce over 88% of the nation's electricity.[24]

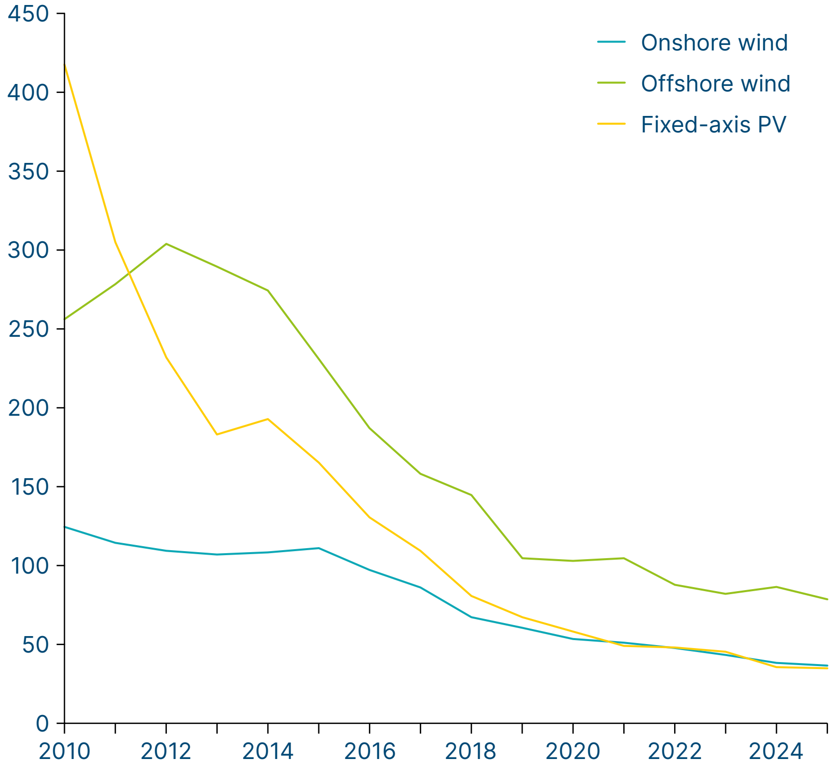
The feasibility of achieving such high shares of wind and solar is still being debated in many countries, including concerns that a grid reliant on renewables could become technically unstable beyond a certain threshold.[25,26] At the same time, many policymakers fear that renewable-dominated systems may ultimately prove more expensive once the full costs of storage, flexible backup capacity, and grid integration are taken into account.[27,28,29]

The crucial question explored in this chapter is how to effectively balance electricity demand and supply in systems with high shares of variable renewables, and the associated cost implications.

Exhibit 1.3

As highlighted by BNEF, rapid declines in renewable technology costs are accelerating clean electrification

BNEF levelised cost of electricity (LCOE) generation for selected technologies
$ per MWh (real 2024)



	2025 expected LCOE ($/MWh)	% change between 2010 and 2025
(Onshore wind)	37	-71%
(Offshore wind)	79	-69%
(Fixed-axis PV)	35	-92%

NOTE: The LCOE is the long-term breakeven price a power project needs to recoup all costs and meet the required rate of return. The global benchmarks are capacity-weighted averages using the latest country estimates. Offshore wind includes offshore transmission costs. LCOEs do not include subsidies or tax credits or transport, storage, and distribution costs. Table values have been rounded to the nearest ten.

SOURCE: BNEF (2025), *Levelized Cost of Electricity Update 2025*

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[20] Climate Change Committee (2025), *The Seventh Carbon Budget.*

[21] ICCSD (2022), *China's Long-Term Low-Carbon Development Strategies and Pathways.*

[22] The 1.5 ° scenario from ICCSD expects that the additional generation mix will comprise of 10% hydropower, 2% gas, 16% nuclear, 6% coal and 2% other. This weighting places higher emphasis on hydropower and baseload generation than other countries.

[23] TERI (2024), *India's Electricity Transition Pathways to 2050: Scenarios and Insights.*

[24] IESR (2021), *Deep Decarbonization of Indonesia's Energy System: A Pathway to Zero Emissions by 2050.*

[25] Man Group (2022), *Against Utopia: The Need for a Pragmatic Energy Transition.*

[26] Gonzalez, T and Knox, J (2023), *In The Dark: The Scapegoating of Renewables After Grid Failures.*

[27] House of Lords Library (2025), *Costs of net zero by 2050.*

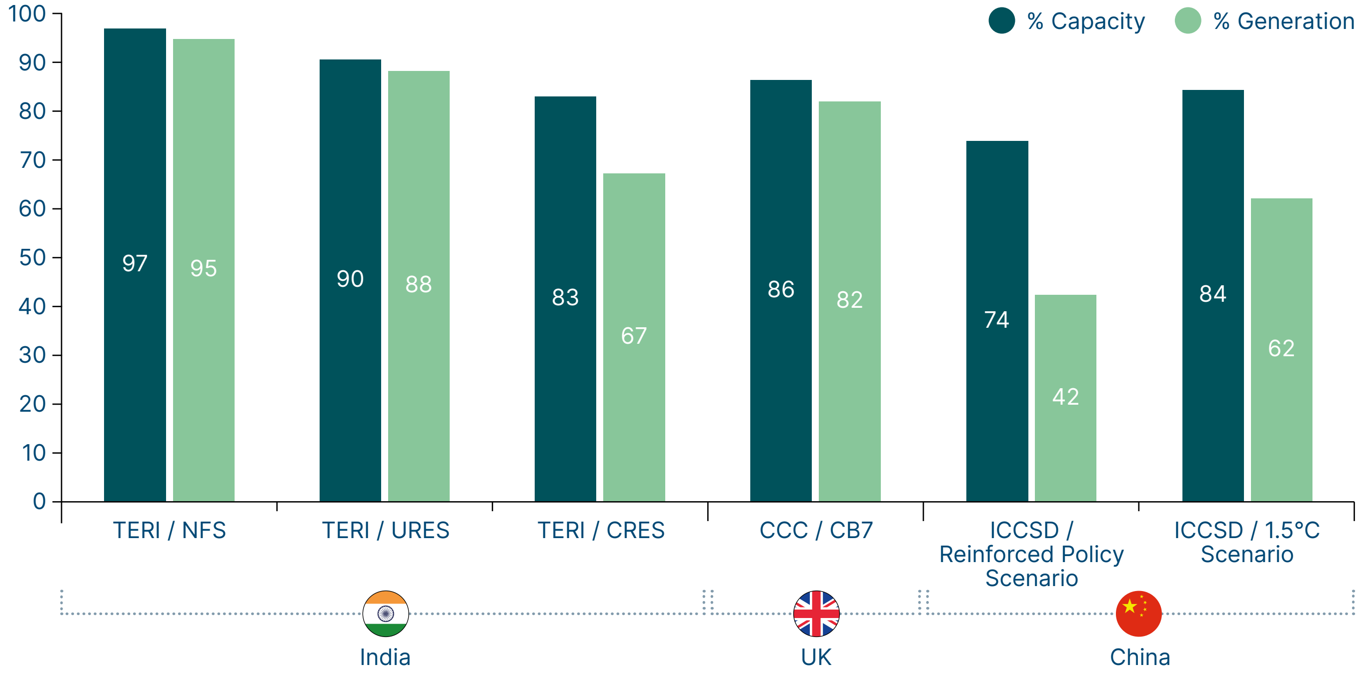
[28] Vance, J. D. (2024), *Net-zero policies stifle infrastructure investment and raise costs.*

[29] O'Brien, L. (2023), *Calls for exit from the Paris Agreement over net-zero impact on energy prices.*

Exhibit 1.4

Future projections of electricity systems show high shares of wind and solar generation

Share of wind and solar as part of total generation and capacity in 2050 across different scenarios and countries



NOTE: For India, TERI refers to The Energy and Resources Institute with scenarios as follows: No Further Support (NFS), Unabated Renewable Energy Scenario (URES) and Combined Renewable Energy Scenario (CRES). CCC refers to the UK Climate Change Committee. ICCSD stands for the Innovation Center for Clean-Energy System Decarbonization (China); its "Reinforced Policy Scenario" reflects current and strengthened policy trajectories, while the "1.5°C Scenario" aligns with limiting global warming to 1.5°C and achieving net-zero emissions by 2050.

SOURCE: CCC (2025), *The Seventh Carbon Budget*; ICCSD (2022), *China's Long-Term Low-Carbon Development Strategies and Pathways*; TERI (2024), *India's Electricity Transition Pathways to 2050: Scenarios and Insights.*

1.2 Types of balancing challenges

There are two different dimensions to the balancing challenge: 1) the technical challenge of ensuring stable system operations and 2) matching energy supply and demand across a range of timescales.

1.2.1 The technical challenge: Ensuring stable system operation

Power systems must maintain grid stability across very short, near-instantaneous timescales. Traditional systems, where most electricity was generated by spinning turbines, driven by fossil fuels, nuclear heat, or hydropower, were designed to achieve stability through specific mechanical and control features. However, stability must be delivered in new ways in systems dominated by wind and solar. Existing technologies are already capable of addressing the key technical stability challenges, but it is essential to plan in advance for their deployment.

Types of technical balance challenge and available technologies:

There are three major technical challenges:

- The need to manage system inertia, which is required to ensure grid stability and appropriate frequency response.[30] In the past, large rotating generators provided natural inertia to resist sudden changes in supply and demand. As these plants phase out, grid operators are deploying new technologies such as synchronous condensers and grid-forming inverters to replicate these stabilising functions [Box A] and batteries used for rapid-response frequency support.
- The need to control voltage, as voltage should be kept within a safe range to ensure system stability, which can be done by deploying control technologies such as Static Var Compensators (SVC), Static Var Generators (SVG), Static Synchronous Compensators (STATCOM), or Thyristor-Controlled Series Capacitors (TCSC).[31]
- The need for wind and solar generation units to remain connected and operational during and after a fault condition, such as a voltage dip or short circuit, without tripping. This can be addressed through grid code standards requiring sufficient high and low voltage ride-through (HVRT/LVRT) capability. It is also important to consider Rate of Change of Frequency (RoCoF) standards, which play a key role in fault response and stability but may need to become more flexible to accommodate higher shares of wind and solar.[32]

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[30] Stable system operation requires instantaneous supply/demand balance to maintain frequency within an acceptable range. If supply and demand are in significant imbalance, frequency deviations can cause generating units to trip off.

[31] Rocky Mountain Institute and ETC (2019), *Zero-Carbon China: Achieving Net-Zero Emissions by 2050.*

[32] MDPI Energies (2023), *Review of RoCoF Estimation Techniques for Power Systems with High Penetration of Renewable Energy*. Available at https://www.mdpi.com/1996-1073/16/9/3708. [Accessed February 2025].

The deployment of these technologies, alongside the continued presence of some turbine-based generation, such as hydropower, gas, or biomass, in future power systems, will enable the reliable operation of electricity systems with 70% or higher share of wind and solar. This is not only theoretically feasible but has already been demonstrated today across periods of high wind and solar generation.

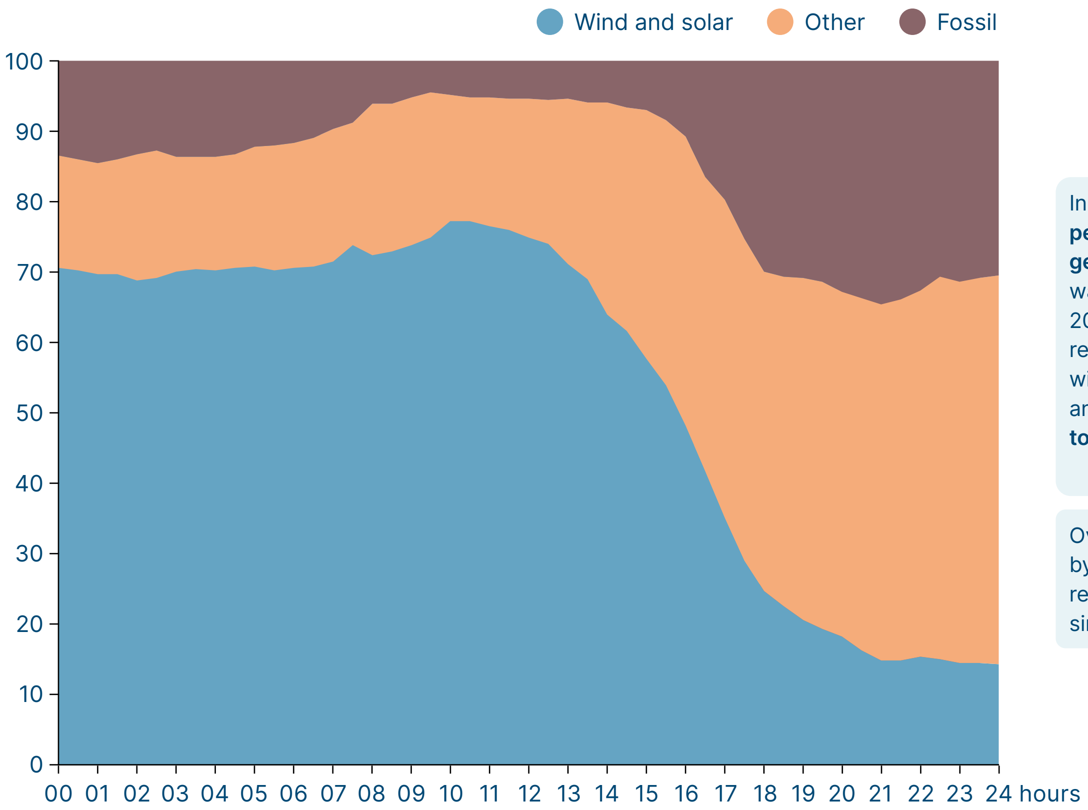
While Exhibit 1.7 above presents current and projected annual wind and solar shares, much higher shares have been observed over shorter timescales relevant to system stability [Exhibit 1.5]. In 2025, wind and solar have accounted for over 78% of electricity generation in the UK[33] during specific hours, and over 79% in Germany.[34] Major system operators in both countries have confirmed that even higher instantaneous shares are operationally manageable.

The UK National Energy System Operator (NESO) foresees no insurmountable technical barriers to operating a system that, by the mid-2030s, generates around 70% of annual electricity from wind and solar. On certain days and hours, this share is expected to exceed 80%, and in specific hours, particularly during nuclear outages, it could rise above 95%.[35]

Exhibit 1.5

UK grid already reaching above 75% of total generation from renewables

UK Electricity generation mix with highest percentage from renewable energy, 30 March 2025
% of total generation



In the UK, the **highest percentage of system generation by renewables** was set on 30th March 2025 at 10:30 AM where renewables (including wind, hydropower, biomass and solar) made up **78% of total generation.**

Over 70% of generation by renewables has been reached in over 145 days since 2022.

NOTE: Renewables includes generation from wind, hydropower, biomass and solar; Other includes generation from nuclear, biomass, imports and "other" (smaller generation methods like landfill gas, sewage gas, biofuels); Fossil fuels includes generation by coal and gas.

SOURCE: NESO (2025), *Historic generation mix and carbon intensity.* Available at https://www.neso.energy/data-portal/historic-generation-mix. [Accessed April 2025].

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[33] NESO (2025), *Historic generation mix and carbon intensity.*

[34] Energy-Charts (2025), *Total net electricity generation in Germany in 2025*. Available at https://www.energy-charts.info/charts/power/chart.htm?c=DE&source=total&interval=year. [Accessed February 2025].

[35] NESO (2024), *Clean Power 2030.*


3010.33
096.56
4333.55
5647.99
2765.31

Box A

System inertia: Needs and Solutions for a wind and solar dominated grid

The challenge of maintaining grid stability on very short timescales, ranging from seconds to minutes, has traditionally been managed through system inertia provided via the use of dispatchable fossil fuel plants. In fossil fuel plants, large rotating generators provided inertia, a natural resistance to sudden changes in grid frequency, alongside the capability to quickly ramp generation up or down to match supply and demand. However, as power systems shift towards wind and solar, which often lacks inherent inertia and dispatchability, maintaining stability has required new technologies.

Grid operators, including the UK's NESO, are increasingly deploying new inertia technologies such as synchronous condensers and grid-forming inverters to maintain grid stability as renewable electricity penetration rises:

- Synchronous condensers, already in use at sites like the Lister Drive project in Liverpool, replicate the inertia traditionally provided by large spinning turbines, delivering critical frequency stability, voltage control, and short-circuit strength without relying on combustion-based generation.[36] These cost-effective devices consist of large rotating synchronous machines – typically repurposed steam turbines or dedicated flywheels – electrically energised from the grid. While not without capital cost, they represent a comparatively low-cost and mature technology for providing essential system strength and dynamic stability services.[37,38]
- Inverters play a critical role in converting electricity from renewable sources such as wind and solar into a form compatible with the grid. There are two primary types: grid-following inverters, which rely on an existing grid signal to synchronise, and grid-forming inverters, which can independently establish and regulate grid frequency.[39] The latter is particularly significant for maintaining grid stability, as it replicates the function of traditional synchronous machines.
- By providing a stable frequency reference, grid-forming inverters enable other grid assets to synchronise effectively, thereby supporting system inertia and frequency stability. This capability is especially important during periods of high variable renewable generation when conventional sources of inertia are limited.[40] In addition to supporting system stability during normal operation, grid-forming inverters also offer black start and recovery capabilities, enhancing system resilience not just by preventing instability, but by enabling rapid rebound and restoration following major outages. Grid-forming inverters are being deployed in Great Britain through NESO's Stability Pathfinder programme, with private developers delivering the country's first grid-forming batteries to provide synthetic inertia, short-circuit strength, and support black start capability.[41] Similar technologies are also being trialled by system operators in other countries, including Australia, Germany, and the United States, to enhance grid resilience as renewable penetration increases.[42]
- Battery storage can also contribute to grid stability through the provision of fast frequency response, synthetic inertia, voltage support, and black start capabilities.[43] When paired with advanced power electronics, batteries can operate as grid-forming resources, helping to stabilise the system during disturbances and reducing reliance on synchronous assets. Their fast-acting nature makes them particularly effective at responding to short-term fluctuations in high wind and solar systems.
- Additionally, companies like Reactive Technologies have developed advanced measurement tools, such as their GridMetrix technology, which provides real-time, accurate measurements of grid inertia and system strength, enabling operators to make informed decisions on future market needs to maintain stability as renewable integration increases.[44]

These technologies, alongside advanced grid management tools, are crucial for balancing supply and demand in low-carbon power systems and ensuring system resilience as the share of wind and solar generation grows.

Collectively, the successful usage of these technologies indicates that power systems can maintain stability and reliability through the use of IGTs as the reliance on fossil fuel plants for short-term balancing diminishes.

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[36] Watt-Logic (2021), *Synchronous condensers help stabilise the GB electricity grid.* Available at https://watt-logic.com/2021/02/15/synchronous-condenser/. [Accessed March 2025].

[37] Wang, C. et al. (2022), *Cost Analysis of Synchronous Condensers Transformed from Thermal Units.*

[38] Thunder Said Energy (2023), *Synchronous Condensers: The Economics.*

[39] National Renewable Energy Laboratory (2023), *Introduction to Grid Forming Inverters.*

[40] Energy Storage News (2023), *Grid-forming technology and its role in the energy transition.* Available at https://www.energy-storage.news/grid-forming-technology-and-its-role-in-the-energy-transition/. [Accessed January 2025].

[41] NESO (2024), *Great Britain's First Grid-Forming Battery Connects in Scotland.*

[42] IEA (2023), *Grid-Forming Inverters: Enabling the Energy Transition.* AEMO (2022) *Engineering Framework – Grid-Forming Capabilities;* NREL (2020) *Grid-Forming Technology: A Key to Resilient Power Systems.*

[43] Australian Energy Market Operator (2021), *Hornsdale Power Reserve Year 3 Technical and Market Impact Report.*

[44] Reactive Technologies (2024), *GridMetrix – Real-time Inertia Measurement for Grid Stability.*

Deploying available grid stability technologies: deliberate planning is essential

On 28 April, there was a blackout in Spain and Portugal which affected over 10 million people. This raised concerns about the technical challenges of operating power systems with very high wind and solar shares, as the event occurred on a day when solar power provided about 59% of total supply and wind 12%,[45] in addition to nuclear at 11% and natural gas at 5%.[46] According to the preliminary report published by the Spanish government in June 2025, the event was triggered by a combination of voltage and frequency instability after a series of generator trips in southern Spain, leading to the progressive separation of the Iberian grid from the wider European system. The report also notes that the complexity of the event requires that there be further technical investigation into the causes surrounding the event.[47]

This event illustrates the need for increased and carefully planned deployment of the available technologies and approaches discussed above. Key points to note are that:

- Large-scale blackouts are not new and have occurred in the past in fossil fuel dominated systems. The 1965 Northeast blackout in the U.S. and Canada was triggered by a relay failure;[48] the 2021 Texas blackout was driven by natural gas supply disruptions and generator outages during extreme cold;[49] and the UK has experienced major blackouts linked to lightning strikes and underperforming protection systems.[50]
- In the Iberian case, the blackout was initiated by a sudden voltage spike following successive generation outages near Granada, Seville and Badajoz. Although protection systems and plants were expected to contain the disturbance, several units failed to respond effectively due to limitations in their configuration and a lack of coordination under stressed conditions. The resulting instability could not be contained due to insufficient synchronous generation and low system inertia, ultimately leading to cascading failures and separation from the continental grid.[51] This suggests a fundamental lesson: as conventional sources of inertia such as fossil plants are phased out, grid stability must be deliberately engineered. This requires coordinated system planning to integrate a diverse set of technologies across all levels of the grid. These include synchronous condensers for rotational inertia and voltage support, grid-forming battery energy storage systems capable of providing synthetic inertia and fast frequency response, and advanced inverter control technologies. Effective deployment depends not only on the rollout of these technologies, but also on enhanced system visibility, real-time data and digital tools, including AI, to optimise performance and manage system stability dynamically. In particular, real-time visibility into all sources of generation is required, including behind-the-meter solar systems. In markets like Spain, where self-consumption PV has grown rapidly, large volumes of solar capacity remain unregistered or untracked, making it harder for system operators to accurately assess net demand or manage frequency.[52] Delivering this transition will require targeted investments in the grid and enabling technologies, as discussed further in Chapter 4.

Maintaining stability in high-renewable systems also depends on strong regulatory and operational foundations. This includes robust grid codes that mandate features such as high-voltage ride-through (HVRT) and frequency response capabilities for inverter-based resources, ensuring they support rather than disconnect during disturbances.[53] In addition, the blackout highlights the importance of system-wide coordination, including protection schemes, real-time monitoring, and automated control strategies that ensure the grid remains resilient under stress. This includes:

- Clear rules for device disconnection thresholds to avoid tripping of large volumes of generation or load with a short time duration.
- Ensuring behind-the-metre resources (e.g., rooftop PV, batteries) remain operational where safe, to support local resilience.
- Improved coordination and fault management across interconnectors, particularly where High Voltage Direct Current (HVDC) and Alternating Current (AC) behave differently under stress, as seen in this incident.

Ireland provides a leading example of how technical stability challenges can be managed through coordinated planning, market design, and targeted infrastructure deployment. The DS3 Programme (Delivering a Secure, Sustainable Electricity System) was launched to prepare the grid for high levels of non-synchronous generation -

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[45] The Breakthrough Institute (2025), *It's Okay to Notice When Solar and Wind Fail.*

[46] Balkan Green Energy News (2025), *Spain's voltage control was insufficient at time of April blackout.*

[47] MITECO (2025), *Informe del Comité de Análisis de la Crisis Eléctrica del 28 de abril de 2025*

[48] Relay failure refers to the malfunction or misoperation of protection relays - devices designed to detect faults and initiate circuit breaker operations. In systems with high shares of inverter-based resources, fast-changing grid conditions can lead to incorrect relay triggers, compromising system stability.

[49] ERCOT (2021), *Review of February 2021 Extreme Weather Event.*

[50] National Grid ESO (2019), *Final Report into the 9 August 2019 Power Outage.*

[51] MITECO (2025), *Informe del Comité de Análisis de la Crisis Eléctrica del 28 de abril de 2025.*

[52] BNEF (2025), *Spain's Power Grid Collapse Exposes Solar Data Black Hole.*

[53] EirGrid (2023), *Grid Code Modifications for Non-Synchronous Generation.*

regularly operating at up to 75%.[54] The programme introduced a comprehensive suite of technical and regulatory reforms, including:

- Grid integration standards for inverter-based resources, including fast frequency response (FFR) and synthetic inertia requirements. Operational limits on system non-synchronous penetration (SNSP) - managing the share of inverter-based resources like wind and solar to ensure stable grid operation, with thresholds adjusted dynamically based on system conditions.
- Development of new procurement mechanisms, such as DS3 System Services, which contract flexible resources (including batteries, flywheels, and synchronous condensers) for specific system support roles.
- Investment in grid stability technologies, including four large synchronous condensers and grid-forming battery installations, such as the 30 MW facility providing grid support in the Midlands.[55]

The DS3 Programme demonstrates that system reliability in high wind and solar contexts is a function of institutional readiness and forward planning. Similarly, in the UK, the stability challenges highlighted by events such as the 2019 blackout have led to investments in synchronous condensers, new frequency response products, and reforms to the National Energy System Operator's (NESO) operational toolkit.

The Iberian event reinforces the urgency of embedding stability planning into system development from the outset, regardless of generation technology. As detailed in Chapter 4, grid stability must now be treated as a core design constraint and a critical area of investment institutions as part of their strategic vision and planning.

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[54] EirGrid (2022), *System Non-Synchronous Penetration Operational Policy*.

[55] Energy Storage News (2020), *Fluence helping Gore Street's Ireland capacity expansion.*

1.2.2 Matching supply and demand over different timescales

Electricity supply and demand must match across a range of different timescales [see Exhibit 1.6], with the nature of the challenge varying by timescale:

- **Short duration (up to 8 hours)**: Solar generation varies on a predictable day to night pattern but is also subject to less predictable hourly variations due to changing hourly cloud cover which is sometimes challenging to forecast even just a few hours ahead.[56,57] Wind generation sometimes varies systematically within the daily cycle (e.g. with stronger winds at night) but can also vary strongly hour by hour. Daily demand patterns often entail specific predictable peaks (e.g., in early evening residential use in many countries). Mechanisms are therefore needed to adjust supply or demand in line with each other over a diurnal cycle.
- **Medium-long duration (8-50 hours)**: Wind supply can vary significantly from day-to-day or week to week as weather patterns change. Solar supply can also vary day to day, especially in many high latitude countries. Daily demand varies both due to more predictable weekly cycles (e.g., less commercial and industrial demand at weekends) and less predictable developments (e.g., surges of heating demand in cold winter weeks, or in air conditioning (AC) demand during heat waves).
- **Ultra-long duration (50+ hours):** Demand can vary across the year in relatively predictable seasonal patterns (e.g., if heating is electrified in high latitude countries, electricity demand will tend to be higher in winter), and this is sometimes matched by seasonal variations in supply (e.g., wind supply tends to be higher in winters and in some low latitude countries wind supply is concentrated during monsoon periods). However, wind supply can also vary significantly from year to year and in ways which are less predictable e.g., during high latitude winter anticyclones, wind supply may fall for several weeks and this may coincide with high heating demand (the so-called "dunkelflaute" (or dark doldrums) effect).

Exhibit 1.6

Balancing durations across different timespans

System operation	**Short duration balancing** (up to 8 hours)	**Medium-long duration** (8 hours to 50 hours)	**Ultra-long** (50+ hours)
Inertia, frequency response, voltage control, fault ride through.	• Predictable daily: e.g., large daily solar outputbut significant demands during the evening. • Unpredictable daily: deviations from average generation patterns (e.g., cloudy days in summer).	Variations (e.g., seasonal) driven by either: • Demand (e.g., winter heating peak in Europe, air conditioning (AC) peak in southern China or India in summer). • Or supply (e.g., Indian wind during monsoon, European sun in summer).	Primarily unpredictable variations driven by: • Demand (e.g., above normal AC peak from heatwaves; cold period heating demand). • Or supply (e.g., anticyclone wind drought).

SOURCE: Systemiq analysis for the ETC.

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[56] ECMWF (2023), *Scale-dependent verification of precipitation and cloudiness at ECMWF*.

[57] Accurately balancing supply and demand across these timescales depends heavily on the quality of weather forecasting, which has improved significantly in recent years. Forecasts now enable system operators and asset managers to anticipate solar and wind generation with increasing confidence up to several days, or even weeks, ahead, with higher accuracy closer to real time. Wind generation, in particular, benefits from relatively consistent and forecastable weather patterns at relevant scales, making it easier to integrate into day-ahead and intra-day system planning. However, solar generation poses a unique challenge at shorter timescales: minute-by-minute fluctuations driven by localised cloud cover occur at spatial scales of tens to hundreds of metres, well below the resolution of most operational weather models, which typically operate at km-scale grids. As a result, while broad solar availability can be forecast accurately, intra-hour variations remain difficult to predict, complicating the balancing of supply and demand on sub-daily timescales.

1.3 Regional differences in balancing needs

Different countries will have inherently different balancing characteristics, due to differences in wind and solar resource, as well as the shape of demand due to different residential and commercial end use patterns.

Exhibit 1.7 shows key differences between four different “regional archetypes “:

- **High latitude regions** such as the UK, Germany and Canada have strong wind potential but lower solar potential due to shorter winter days and lower sun angles. Electricity demand is expected to peak in winter in the future as heating becomes increasingly electrified.
- **Low latitude**, including India, Thailand, and Mexico, have high solar irradiance with some limited seasonal variability due to monsoons. Cooling is a major driver of increasing power demand because of rising prosperity and rising temperatures.
- **Mediterranean regions**, such as Spain, Australia, California and Chile, benefit from strong summer solar generation and moderate wind availability, with demand higher in hotter months due to cooling needs.
- **Countries with mixed climates**, such as China, the United States, and Chile, span large geographic areas with substantial variation in wind and solar resources across regions. These regional differences often result in complementary generation profiles, which can help smooth variability in supply. When supported by long-distance, high-capacity transmission infrastructure, such geographic diversity can significantly enhance the ability to balance electricity supply and demand at the national level.

To assess the scale and nature of the balancing challenge across the different system archetypes, we have modelled four representative countries - China, India, Spain, and the UK. For each, we compare potential future demand variation with wind and solar supply under an illustrative scenario in which wind and solar capacity is sized to meet 100% of annual electricity demand [see Box B for methodology].

This is clearly an unrealistic assumption, since almost all zero carbon power systems will include other generation sources such as nuclear, hydropower, geothermal or dispatchable gas with CCS. As a result our scenarios will tend to overstate both the scale of the balancing requirement and implications for total system costs. But these scenarios

Exhibit 1.7

Regional archetypes used in ETC Balancing Model

Key characteristics	**Archetype 1:** High latitude Case Study: 🇬🇧	**Archetype 2:** Low latitude Case Study: 🇮🇳	**Archetype 3:** Mild/Mediterranean Case Study: 🇪🇸	**Archetype 4:** Mixed climate Case Study: 🇨🇳
Solar irradiance	Relatively low	High with moderate seasonality (e.g., monsoon season lower)	Plentiful in summer, less in winter	Varied, high in places
Wind speed	Generally high & consistent	Mixed, high in places	Relatively high & consistent	Varied, high in places
Heating need	Signficant	Generally low	Moderate	Varied
Cooling need	Generally low	High throughout the year	High in summer	High in summer, large variation
What does archetype represent?	Most northern countries: North Europe, Canada, etc.	Many tropical countries: Thailand, Vietnam etc.	Many milder climates: Italy, Turkey, etc.	Very large varied countries: Argentina, Chile, Mongolia, and US etc.

SOURCE: Systemiq analysis for the ETC.

enable us to examine the maximum potential scale of power surpluses and deficits, and how the nature of the balancing challenge varies by different region and archetypes. This in turn helps identify where and why other power sources are likely to need to play a role in cost effective decarbonisation.

Given the unrealistic and illustrative nature of our scenarios, Section 1.6 compares our estimated implications for total system generation cost with those produced by other organisations which use dispatch models to identify cost minimising combinations of generation sources.

Box B describes how the model quantifies the temporal variation in both electricity demand and wind and solar output, and the resulting imbalances between supply and demand.

Box B

Modelling the balancing need

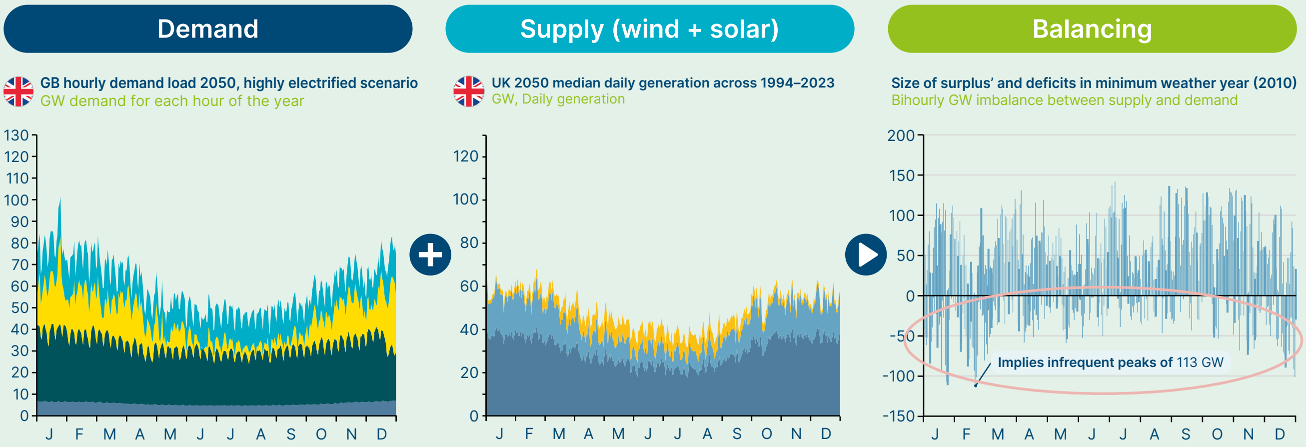
Overview: The ETC's model illustrates the scale of the balancing challenge and estimates balancing costs for four regional archetypes. The model starts by assuming 100% generation from wind and solar, with no generation from fossil fuels, nuclear, geothermal, hydropower and no interconnection to other countries.

While some sources of low-carbon baseload can meet a share of the total balancing needs, it typically cannot fully solve the issue presented by wind and solar generation and other balancing solutions will still be needed in systems with some low-carbon baseload generation. For example, even large nuclear fleets such as France's are only moderately flexible, with limited ability to ramp rapidly or follow demand on intra-day timescales and are often prioritised for baseload operation to maintain economic viability.[58] Therefore, excluding low carbon baseload is useful to understand the balancing patterns. Future ETC work will explore the role of low-carbon baseload in more detail.

How the model is structured: The ETC's balancing model assesses three key components [Exhibit 1.8] for four countries, representing each of the archetypes discussed above. As shown in Exhibit 1.8 above, the chosen countries were the UK to represent High Latitude, India for Low Latitude, China for Mixed Climate and Spain for Mediterranean regions.

Exhibit 1.8

Structure of ETC Balancing Model



Detailed 2050 hourly load profiles obtained from expert forecasters which are reflective of high electrification and specific peak profiles (i.e. UK ESO, TERI in India)

Bihourly weather data obtained for past 30 years (1994-2023); assumed wind and solar deployment for each country*; weather patterns applied to renewables to provide generation across low-high scenarios)

Matching at bi-hourly level across demand and supply to assess periods of wind & solar generation excess/shortfall relative to demand

NOTE: The ETC's balancing model assesses demand, supply of wind and solar, and balancing sizing for the UK, India, China, and Spain. Our demand analysis is based on detailed 2050 hourly load profiles, and our supply analysis on bihourly weather data from 1994 to 2023. The demand and supply data is matched every 2 hours to assess periods and wind and solar generation excess and shortfall relative to demand.

SOURCE: Systemiq analysis for the ETC.

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[58] BNEF (2023), *Power Transition Trends: Flexibility in Low-Carbon Grids.*

- **Demand Analysis:** Detailed 2050 hourly load profiles obtained from expert forecasters[59] which are reflective of high electrification and specific, hourly profiles based on future loads (e.g., EVs, heat pumps) and patterns in a fully electrified system. The demand profiles used excluded demand side flexibility (or demand side response), in order to understand the "baseline" extent of demand peaks. Profiles are shown below in Exhibit 1.9 below.
- **Supply Analysis**: Bihourly weather data was obtained from 1994 to 2023 using ERA 5 wind speed and solar irradiation data for each country and the Atlite open-source python model for conversion to renewable generation potential across a granular view of the Earth's surface.[60] We then overlaid this with initial assumptions of wind and solar installed capacities for each country, based on assessments of government targets, as well as other studies. By applying historical weather patterns to these capacities, renewable generation for each year was estimated, developing minimum, average, and maximum scenarios based on the variation in output from different weather years. However, possible future shifts in weather patterns due to climate change were not accounted for in this analysis. Supply profiles can be seen in Exhibit 1.10.
- **Balancing Sizing:** Demand and supply data were then matched every two hours to assess periods of wind and solar generation excess and shortfall relative to demand. Based on this matching, we then assessed the extent to which deficits could be met by different balancing technologies, by assuming a given capacity in each system of short, medium-long and ultra-long duration storage capacity. Storage deployment assumed that a sequential deployment of energy storage - with short-duration storage deployed first until depleted, followed by medium-long-duration storage for 10 to 50 hours, and finally ultra-long duration storage for needs exceeding 50 hours.
- **Sensitivity Analysis**: 10–15 variations of supply and balancing sizing combinations were compared for each country to determine the optimal system designs, ensuring that supply with balancing met the demand profile at all times, with the lowest total system generation and balancing cost. This optimisation aimed for the lowest total system cost while accounting for buildout feasibility in line with government targets and industry projections.

It is important to note that this model is intended as an illustrative case rather than a predictive forecast. In practice, real-world power systems will incorporate a wider mix of resources, face technical, economic and policy constraints, and evolve in response to changing technologies and costs. As such, actual balancing needs and technology choices may differ significantly from those presented here.

The objective of this analysis is to clarify the nature and scale of balancing requirements in deeply decarbonised systems and to inform future system design under high-renewables scenarios. This modelling approach is therefore best understood as representing a technical upper limit to the scale of balancing challenges in fully renewable systems. By assuming 100% wind and solar with no contribution from firm low-carbon sources or interconnection, it explores what is required to cover even the most extreme, infrequent shortfalls in supply — including the "last-mile" of ultra-long duration balancing, which is disproportionately expensive, as shown later in this report in Section 1.5.

While 100% wind and solar systems are technically feasible, they would be exceptionally demanding to build, particularly in wind-dominated countries like the UK. In practice, countries are likely to reduce the total build-out and system complexity by incorporating complementary firm low-carbon resources, such as nuclear, and geothermal, which can reduce the volume of wind, solar, and storage required. The ETC is currently conducting analysis on whether these technologies can act as complementary resources to ease the challenge and potentially lower total system costs.

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[59] UK ESO (2022), *FES 2022*; India - *The Energy Resources Institute* TERI (2024), *India's Electricity Transition Pathways to 2050: Scenarios and Insights*; China – Li, M et al. (2024), *The role of dispatchability in China's power system decarbonisation;* Spain – AFRY (2025), *Hourly Demand Projections*.

[60] See Systemiq Analytiq analysis for the ETC; ECMWF (2024), *ERA5 weather data;* UK Government (2023), *'Untapped potential' of commercial buildings could revolutionise UK solar power*; TERI (2024), *India's Electricity Transition Pathways to 2050: Scenarios and Insights.*

Future demand variation

The patterns of possible future demand variations by region across the year, and for the lowest generation periods (corresponding to the weeks in Exhibit 1.11) on a weekly basis, are shown in Exhibit 1.9. The key takeaways per archetype system are as follows:

- In the UK, electricity demand in 2050 could range from a winter hourly peak of 165 GW to a summer hourly minimum of around 20 GW, primarily driven by seasonal variation in electric heating demand.[61] In addition to this predictable seasonal swing, Exhibit 1.9 shows that demand may vary significantly from week to week in winter, as changing weather conditions affect heating loads (the annual trends on the left show daily averages, while the lowest generation period on the right show hourly data points). Demand also fluctuates on a daily and hourly basis, requiring flexible system operation throughout the year.
- In India, seasonal variation in electricity demand is less pronounced, but there is a strong weekly cycle and considerable day-to-day variability, reflecting industrial and commercial usage patterns.
- In China, the continental scale of the country creates some natural balancing effects. For example, peak heating demand in the north often coincides with lower cooling needs in the south. However, electricity demand is still typically higher during mid-summer due to widespread use of AC, and again in winter months (December and January) due to heating. In recent years, summer AC loads have grown sharply,[62] and a noticeable drop in industrial demand during Chinese New Year is also evident in the data.
- In Spain, electricity demand is shaped by both cooling and heating needs, with peaks in summer due to AC and in winter due to electric heating, daily and weekly demand patterns are also influenced by industrial activity and the timing of agricultural irrigation.

Future supply variation

Wind and solar resources vary significantly across different regions of the world. As shown in Exhibit 1.10, global patterns reveal that solar radiation is generally stronger and more consistent throughout the year in low latitude countries, while wind speeds tend to be higher and more stable in high latitude regions. In many low latitude countries, wind availability is concentrated in specific seasons, such as during the monsoon.

There are important exceptions to these general trends. For instance, solar irradiation levels are lower in equatorial tropical forest regions due to persistent cloud cover, while desert regions benefit from high and relatively constant solar irradiance year-round.

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[61] This peak demand range differs from NESO's Future Energy Scenarios (FES) reports, which use "Average Cold Spell" (ACS) demand – a winter peak with a 50% chance of being exceeded annually. As a statistical average, ACS is lower than the hourly peak demand used in our modelling.

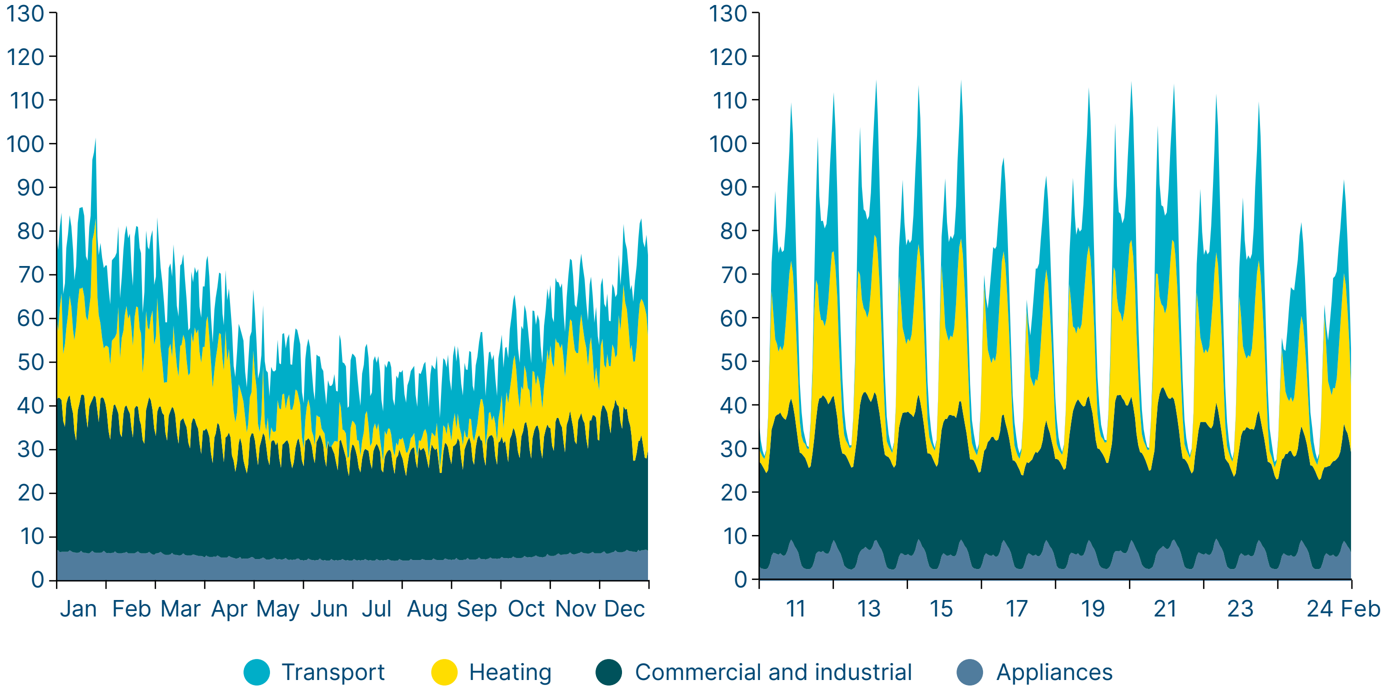
[62] Ember (2024), *Powering through the heat: how 2024 heatwaves reshaped electricity demand*.

Exhibit 1.9

Electricity demand by archetype

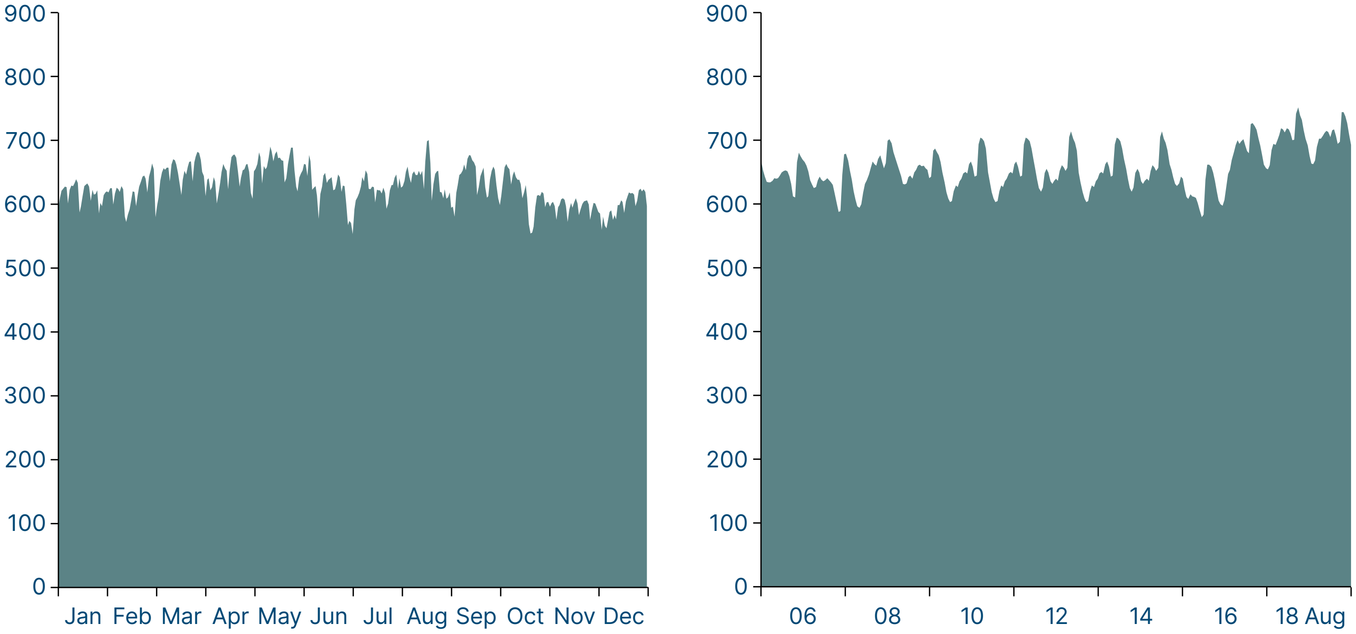
Annual

Demand during lowest generation period



GB hourly demand load 2050, highly electrified scenario
GW demand for each hour of the year

GB 2050 demand, February 11–24
GW demand for each hour over least productive period



Indian hourly demand load 2050, highly electrified scenario
GW demand for each hour of the year

India 2050 demand, August 06–19
GW demand for each hour over least productive period

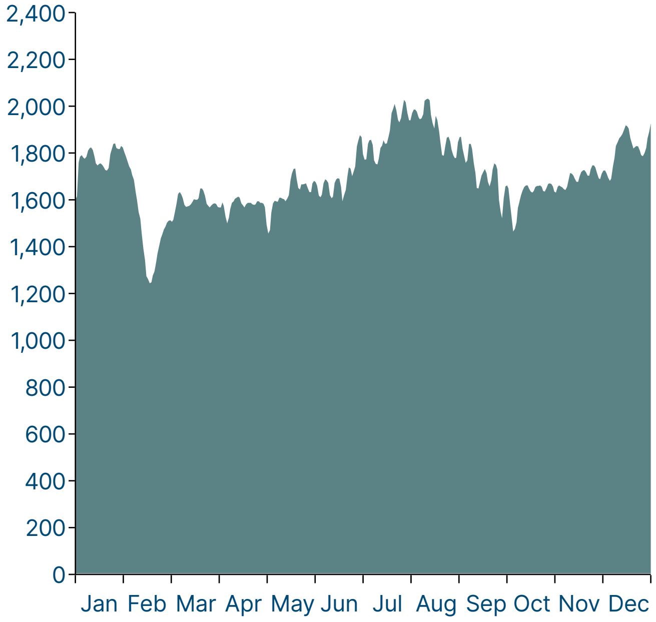
Exhibit 1.9 *cont.*

Electricity demand by archetype

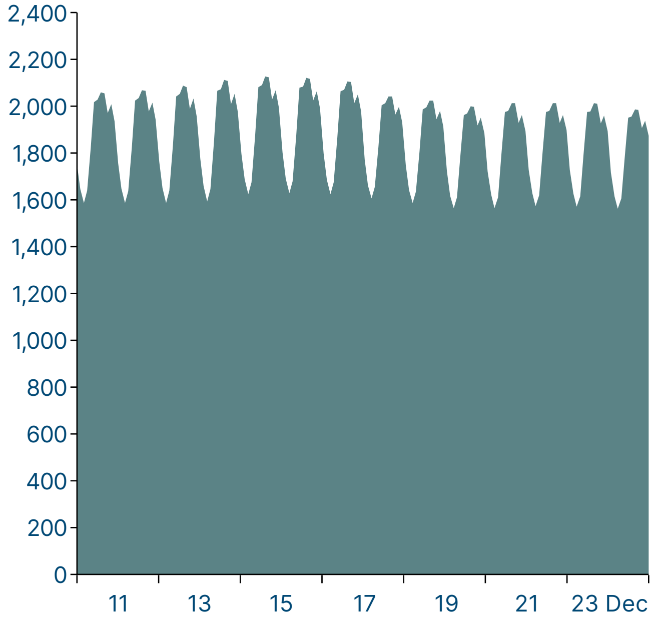
Annual

Demand during lowest generation period

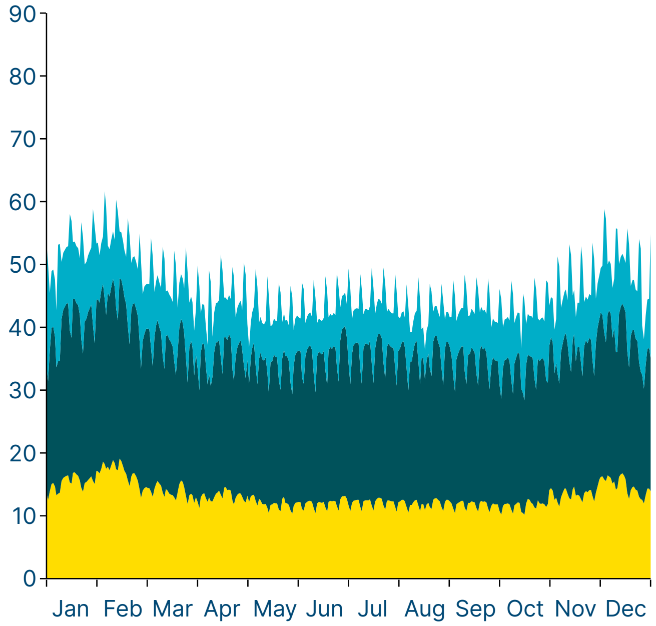
China hourly demand load 2050
GW demand for each hour of the year



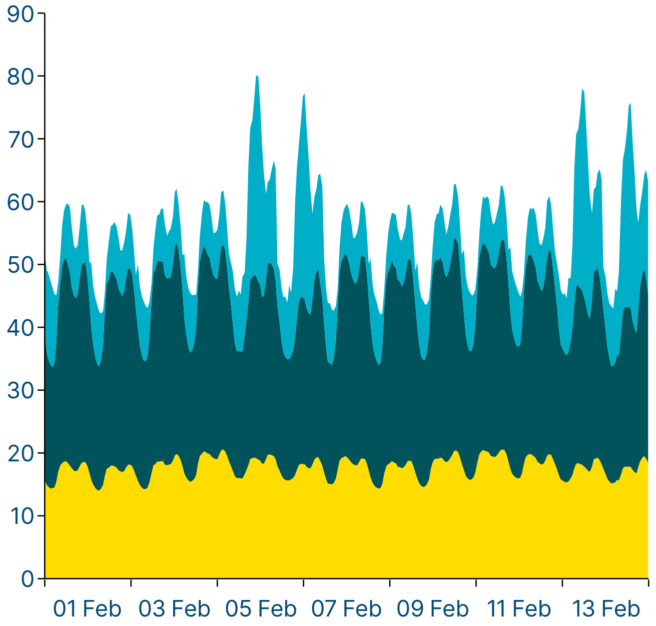
China 2050 demand, December 11–24
GW demand for each hour over least productive period



Spain hourly demand load 2050
GW demand for each hour of the year



Spain 2050 demand, February 01–13
GW demand for each hour over least productive period



● Transport ● Commercial and industrial ● Heating

NOTE: The annual demand trends shown on the left are assumed to be constant across the range of supply years modelled for each archetype. The demand for the lowest supply week from the minimum supply year is shown on the right, representing the lowest supply across all scenarios modelled.

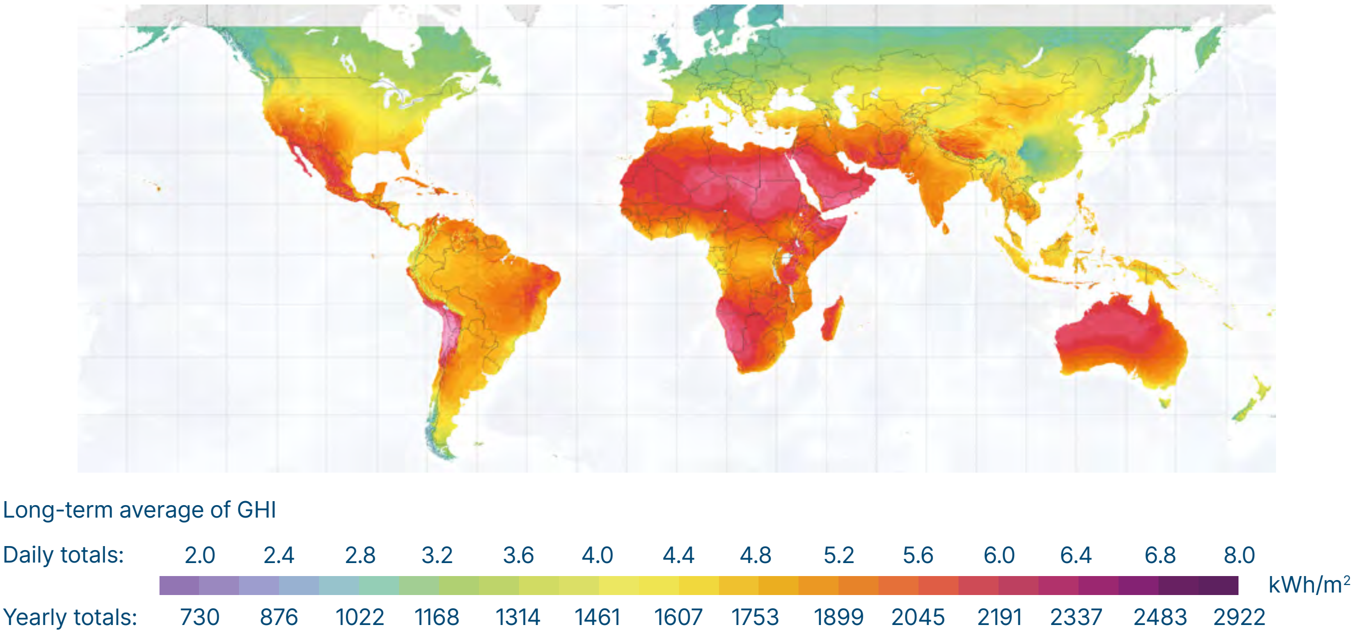
SOURCE: Systemiq analysis for the ETC; UK - UK ESO (2022), FES 2022; India - TERI (2024), *India's Electricity Transition Pathways to 2050: Scenarios and Insights*; China – Li, M et al. (2024), *The role of dispatchability in China's power system decarbonisation*; Spain – AFRY (2025), *Hourly Demand Projections*.

Exhibit 1.10

Wind and solar potential varies greatly with high latitude countries reliant on wind, whilst low latitude countries have vast solar potential

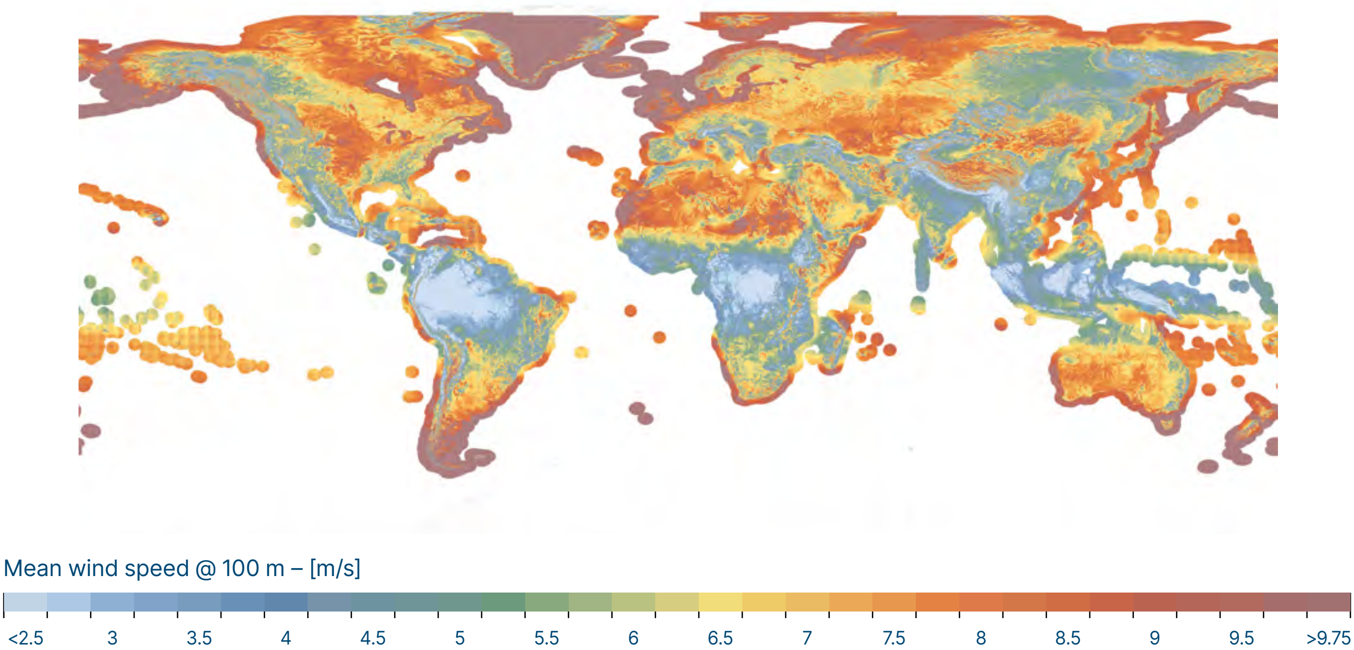
Irradiation varies across the globe

Long-term yearly average of daily and yearly GHI totals



Wind power density also varies substantially

Mean wind power density at 100 m above surface level



NOTE: GHI refers to Global Horizontal Irradiance - the total amount of solar radiation received on a horizontal surface.

SOURCE: Map obtained from the Global Solar Atlas 2.0, a free, web-based application developed and operated by the company Solargis s.r.o. on behalf of the World Bank Group, utilizing Solargis data, with funding provided by the Energy Sector Management Assistance Program (ESMAP). For additional information: https://globalsolaratlas.info. Map obtained from the Global Wind Atlas version 3.3, a free, web-based application developed, owned and operated by the Technical University of Denmark (DTU). The Global Wind Atlas version 3.3 is released in partnership with the World Bank Group, utilizing data provided by Vortex, using funding provided by the Energy Sector Management Assistance Program (ESMAP). For additional information: https://globalwindatlas.info; Neil N. Davis, Jake Badger, Andrea N. Hahmann, Brian O. Hansen, Niels G. Mortensen, Mark Kelly, Xiaoli G. Larsén, Bjarke T. Olsen, Rogier Floors, Gil Lizcano, Pau Casso, Oriol Lacave, Albert Bosch, Ides Bauwens, Oliver James Knight, Albertine Potter van Loon, Rachel Fox, Tigran Parvanyan, Søren Bo Krohn Hansen, Duncan Heathfield, Marko Onninen, Ray Drummond; The Global Wind Atlas: A high-resolution dataset of climatologies and associated web-based application; Bulletin of the American Meteorological Society, Volume 104: Issue 8, Pages E1507-E1525, August 2023, DOI: https://doi.org/10.1175/BAMS-D-21-0075.1.

Exhibit 1.11 illustrates the variation in power supply that would occur in systems where wind and solar capacity has been sized such that, in aggregate, annual generation from wind and solar power could match total annual electricity demand. For each system archetype, we used the projected 2050 wind and solar capacity, applied this to historical hourly weather data from 1994–2023, and extracted the median hourly generation profile across those years. This approach highlights how weather-driven variability would impact system operation even in a system with sufficient annual wind and solar power to meet demand.

- In the UK, a fully renewables-based system would be dominated by wind generation, with typical seasonal peaks in February-March and again in September-October. However, wind output varies significantly from week to week. Solar generation would be substantially higher in summer than in winter and is also subject to considerable intra-day and day-to-day variability.
- In India, solar output declines during the monsoon season due to increased cloud cover, but this is partially offset, at least at the national level, by a concurrent increase in wind generation. While daily solar variability is generally less extreme than in the UK, it remains an important operational consideration.
- China benefits from a large and relatively stable solar resource, particularly in its desert regions, where utility-scale solar megaprojects are under development.[63] With sufficient long-distance transmission infrastructure, this could enable relatively steady solar supply throughout the year. Wind resources, such as those in Inner Mongolia, also show relatively low variability both seasonally and diurnally.
- In Spain, both solar and wind resources contribute significantly to the system. Solar generation is strong and consistent across much of the country, especially in summer, while wind provides an important complement, particularly in winter and in coastal and high regions.

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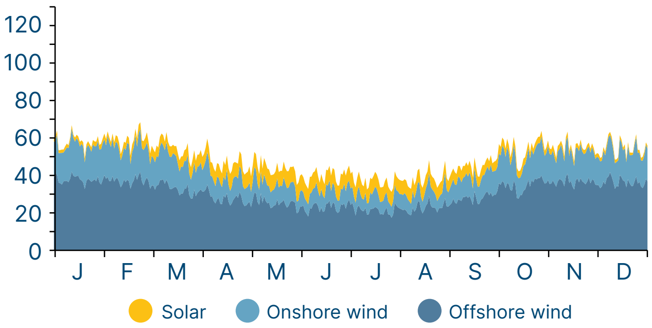
[63] Solar Power Portal (2025), *Large-Scale Solar Archives.*

Exhibit 1.11

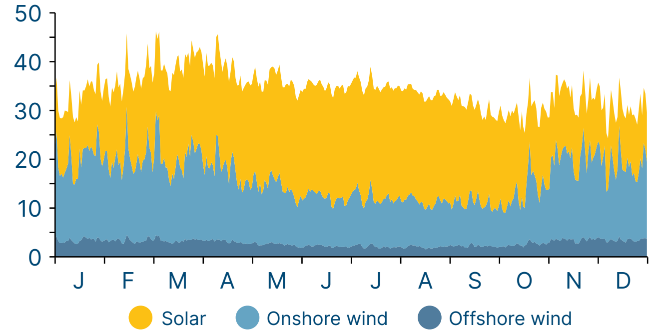
Electricity supply by archetype

Annual

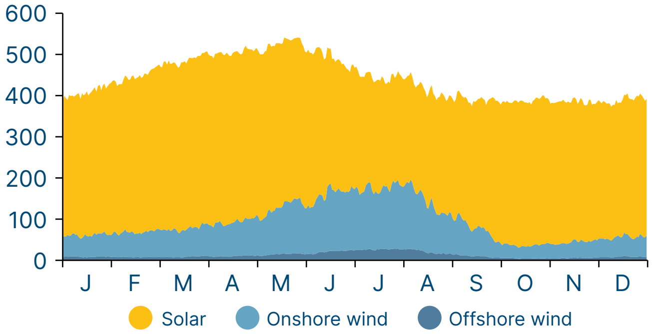
UK 2050 median supply year across 1994–2023
GW daily average generation



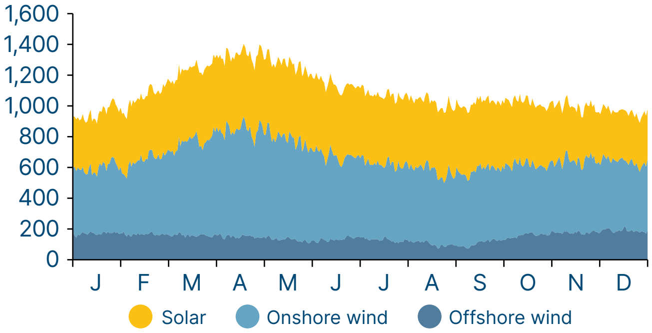
Spain 2050 median supply year across 1994-2023
GW daily average generation



India 2050 median supply year across 1994–2023
GW daily average generation

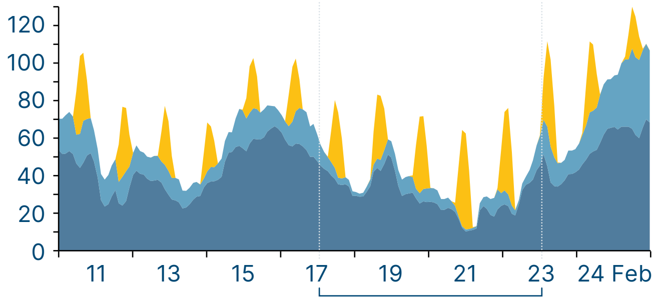


China 2050 median supply year across 1994-2023
GW daily average generation



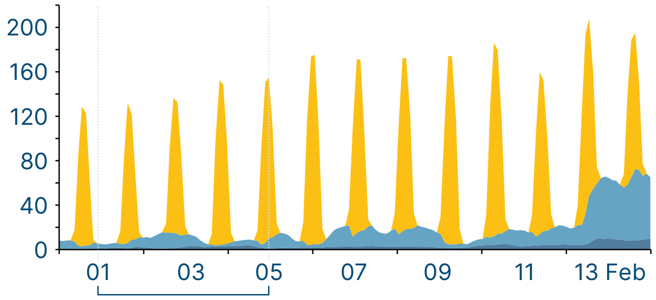
Supply during lowest generation period

UK 2050 generation in lowest supply year (2010), Feb 11–24
GW demand for each hour over least productive period



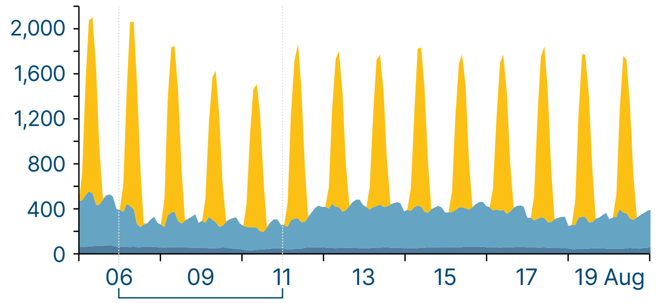
Feb 17th – 22nd = least productive weather period

Spain 2050 generation in lowest supply year (1997), Feb 01-13
GW demand for each hour over least productive period



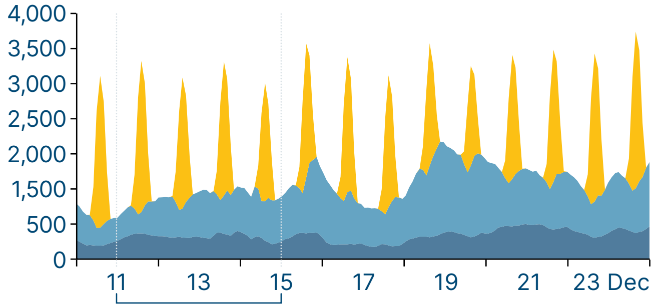
Feb 1st – 5th = least productive weather period

India 2050 generation in lowest supply year (2020), Aug 06–19
GW demand for each hour over least productive period



Aug 6th – 11th = least productive weather period

China 2050 generation in lowest supply year (2002), Dec 11-24
GW demand for each hour over least productive period



Dec 11th – 15th = least productive weather period

NOTE: The annual trend for the median year for each archetype is shown on the left, to show the typical aggregated annual trends and the lowest supply week from the minimum supply year is shown on the right, representing the lowest supply across all scenarios modelled.

SOURCE: Systemiq analysis for the ETC; ECMWF (2024), *ERA5 weather data.* Available at https://www.ecmwf.int/en/forecasts/dataset/ecmwf-reanalysis-v5. [Accessed October 2024]. UK Government (2023), *'Untapped potential' of commercial buildings could revolutionise UK solar power;* TERI (2024), *India's Electricity Transition Pathways to 2050: Scenarios and Insights.*

Nature and scale of the balancing challenge for different regional archetypes

The demand and supply variations can be combined to assess the extent and duration of supply shifts required to match demand. Exhibit 1.12 presents the resulting surpluses and deficits for the UK, calculated as the difference between wind and solar supply and projected electricity demand. The analysis reveals substantial multi-week deficits during certain winter periods, alongside more frequent but shorter-term deficits throughout the year.

The nature of the balancing challenge varies significantly across regions, reflecting differences in the mix of natural renewable resources and in the temporal variability of both supply and demand across multiple time horizons.

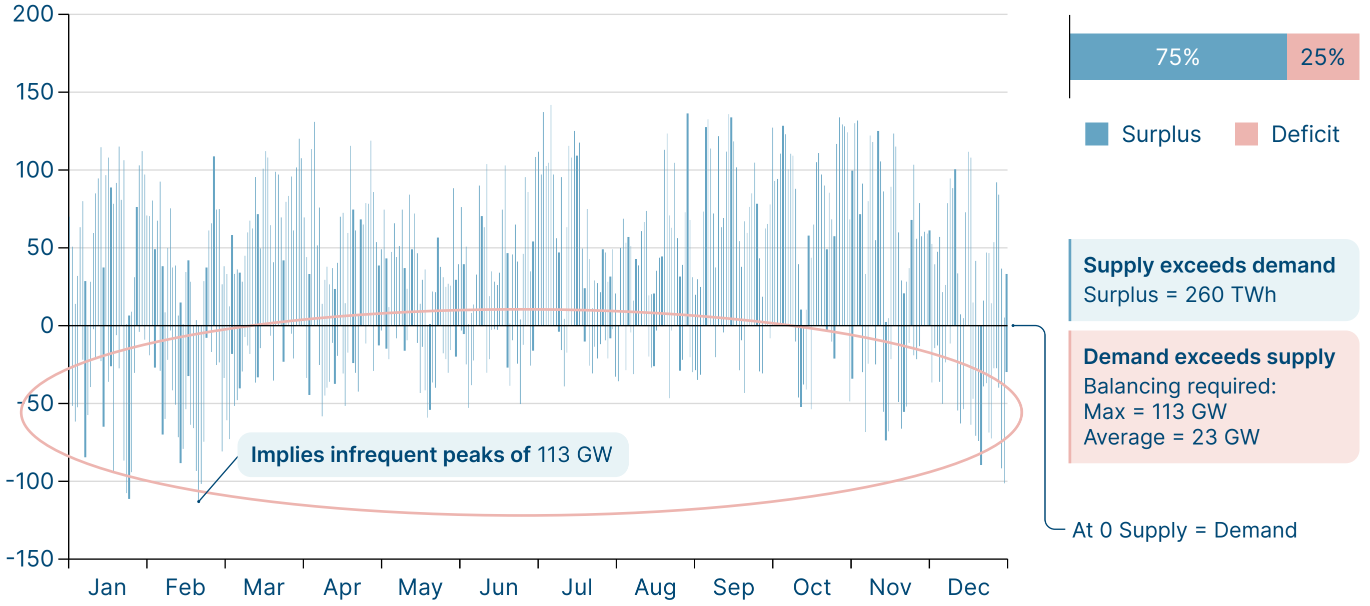
Exhibit 1.12

Minimum weather year: Deficits indicate balancing needs

Size of surplus' and deficits in minimum weather year (GB,2010)

Bihourly GW imbalance between supply and demand

Percent of hours in surplus/deficit



Implies infrequent peaks of 113 GW

Supply exceeds demand
Surplus = 260 TWh

Demand exceeds supply
Balancing required:
Max = 113 GW
Average = 23 GW

At 0 Supply = Demand

SOURCE: Systemiq analysis for the ETC; NESO (2022), *Future Energy Scenarios 2022 (FES 2022);* ECMWF (2024), *ERA5 weather data.* Available at https://www.ecmwf.int/en/forecasts/dataset/ecmwf-reanalysis-v5. [Accessed October 2024].

High latitude system – UK case study

The system presented in this illustrative High Latitude case study in Exhibit 1.13 includes 235 GW of installed renewable capacity, comprising 100 GW offshore wind, 60 GW onshore wind, and 75 GW solar PV. This represents a significant scale-up from today's installed capacity in the UK, which totals around 30 GW of wind and ~15 GW solar (including ~15 GW offshore wind, ~14 GW onshore wind). It also goes beyond current government targets, including the UK's offshore wind capacity targets of 50 GW by 2030 and the NESO's estimated 86 GW potential by 2035.[64] While not intended as a forecast, this scenario reflects the scale of renewable deployment that would be required to deliver a fully wind and solar-powered system.

Modelling indicates that 91% of supply and demand (in kWh terms) would be naturally concurrent across the year. The remaining 9% would require temporal shifting, either by moving supply across time or through flexible demand. Of this, approximately 3% of total supply would need to be shifted over periods of multiple weeks or months. While this is a relatively small share of total energy, the cost and complexity of enabling ultra-long duration balancing makes it one of the most significant challenges in high-wind systems such as the UK.

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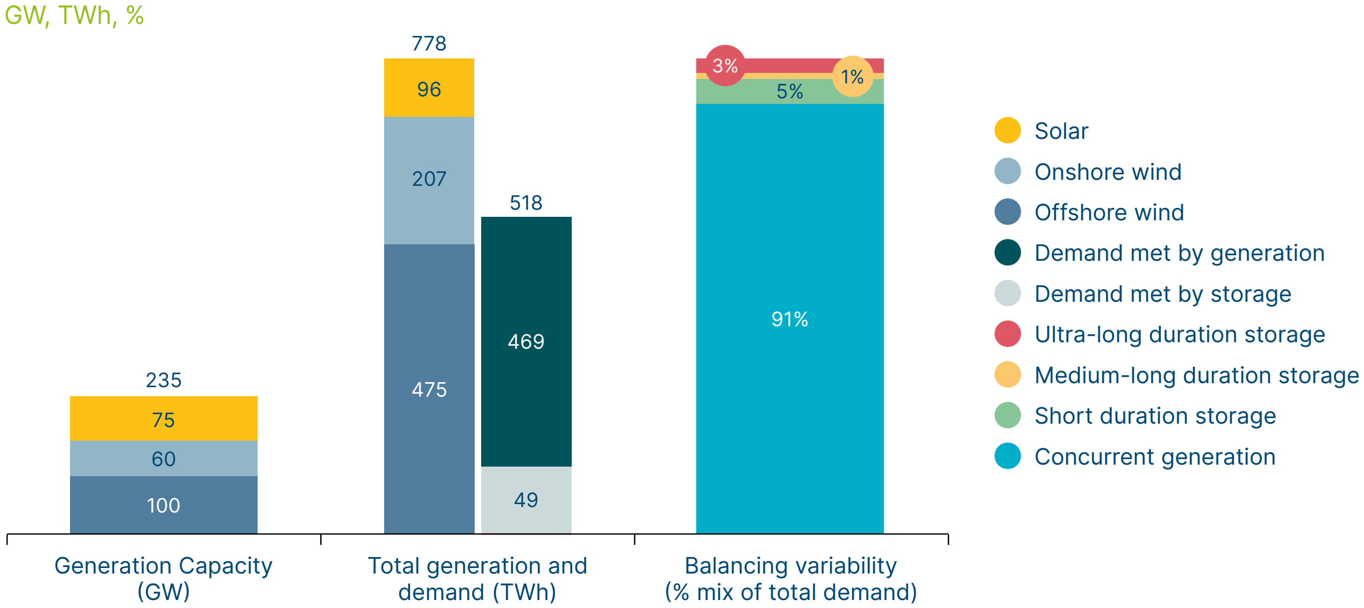
[64] NESO (2024), *Beyond 2030.*

Exhibit 1.13

Generation and balancing mix results for High Latitude archetype (UK Case Study)



Generation

- Wind dominates generation (~88%), with solar providing ~12%.
- Driven by windier conditions in high latitudes.

Balancing Mix

- >90% of wind and solar generation is concurrent, minimal storage is needed during these periods.
- Wind variability (esp. in winter) creates multi-day and seasonal balancing challenges.
- Northern climates require ultra-long duration (50+hrs) and seasonal storage.
- In low-wind years, storage needs could reach 50 TWh to cover 2,200 hours of deficit.
- Peak capacity could exceed 113 GW to manage prolonged lulls.
- Some wind lulls last several days; storage must extend beyond daily cycles.
- May require more gas turbine capacity than today but with low utilisation for backup only.

NOTE: A small share of excess generation is absorbed by storage losses.

SOURCE: Systemiq analysis for the ETC; NESO (2022), *Future Energy Scenarios 2022*; ECMWF (2024), *ERA5 weather data*. Available at https://www.ecmwf.int/en/forecasts/dataset/ecmwf-reanalysis-v5. [Accessed October 2025]; UK Government (2023), *"Untapped potential" of commercial buildings could revolutionise UK solar power.*

Low latitude archetype – India case study

In a stylised 100% wind and solar system for India as shown in Exhibit 1.14, solar would account for approximately 80% of installed capacity. This system could generate around 7,300 TWh of electricity annually by 2050, sufficient to meet projected demand of approximately 5,500 TWh, which is a threefold increase from 2024's total electricity consumption of around 1,600 TWh.[65] Electricity demand is expected to continue rising significantly beyond 2050.

Given the system's strong dependence on solar generation, modelling suggests that ~40% of electricity supply would need to be time-shifted to align with demand, such as to enable cooling loads to continue after sunset. However, the vast majority of this balancing requirement would occur over short durations (intra-day or day-to-day), with minimal need for seasonal or multi-week balancing.

Mixed climate archetype – China case study

By mid-century, electricity consumption in China in Exhibit 1.15 could reach approximately 15,000 TWh per year, up from around 9,000 TWh per year today.[66] In a stylised 100% wind and solar system, this would require around 18,900 TWh of annual generation, accounting for oversized renewables capacity and system losses. While wind and solar capacity would be evenly split under this scenario, wind and solar would provide around 60% and 40% of generation, respectively, driven by differences in capacity factors.

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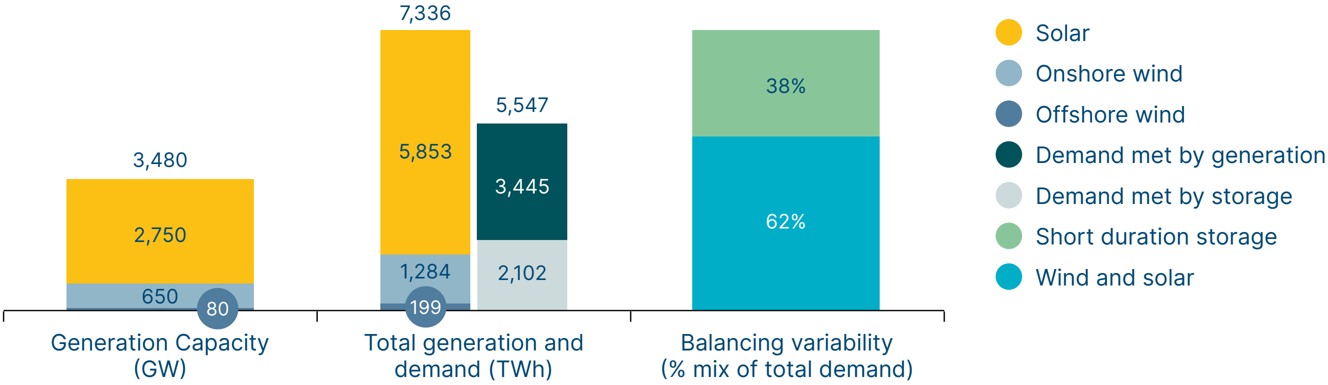
[65] BNEF (2024), *New Energy Outlook.*

[66] BNEF (2024), *New Energy Outlook.*

Exhibit 1.14

Generation and balancing mix results for low latitude archetype (India Case Study)

GW, TWh, %



Generation

- Solar dominates (~80%) due to high irradiation; wind provides ~20%.
- Overbuilding solar is the lowest-cost path to 100% renewables.
- Excess solar helps buffer seasonal lulls (e.g., monsoons).

Balancing Mix

- >60% of generation is concurrent; no storage needed during these periods.
- Remaining 40% covered by short-duration storage for daily (not seasonal) balancing.
- Tropical transitions are cheaper than northern ones due to limited seasonal variability.
- Excess solar must be absorbed via interconnectors, hydrogen, or industrial demand shifting.
- Nighttime generation gaps managed with short duration storage, DSF, and grid optimisation.

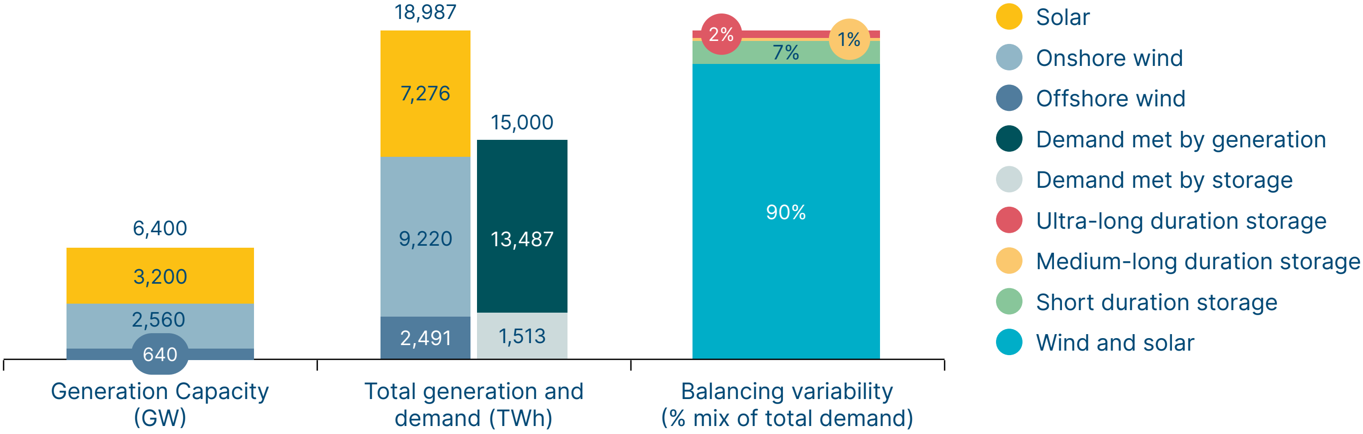
NOTE: A small share of excess generation is absorbed by storage losses.

SOURCE: Systemiq analysis for the ETC; TERI (2024), *India's Electricity Transition Pathways to 2050: Scenarios and Insights.*

Exhibit 1.15

Generation and balancing mix results for mixed climate archetype (China Case Study)

GW, TWh, %



Generation

- Solar and wind are evenly split due to diverse weather patterns.

Balancing Mix

- ~90% of generation is concurrent; minimal storage needed during these periods.
- Regional and seasonal variability drives need for ultra-long-duration storage.
- Daily and seasonal fluctuations supported by short-duration storage.

NOTE: A small share of excess generation is absorbed by storage losses.

SOURCE: Systemiq analysis for the ETC; Li, M et al. (2024), *The role of dispatchability in China's power system decarbonisation.*

Modelling suggests that 90% of electricity supply and demand would be naturally concurrent, comparable to the High latitude case. Short-term balancing would be required for around 7% of total supply, slightly higher than in the UK, while ultra-long duration balancing (over weeks or months) would be needed for just 2%.

However, these figures represent the aggregate national picture. At the regional level, imbalances between supply and demand could be more pronounced. Long-distance, high-capacity interconnection will therefore be critical to enable balancing across China's climatically diverse demand zones.

Mediterranean climate (Spain case study)

By mid-century, electricity consumption in Spain could reach approximately 400 TWh per year. In a stylised 100% wind and solar system, this would require capacity capable of 650 TWh of annual generation, accounting for system losses and curtailment. Both wind and solar would contribute significantly to the generation mix.

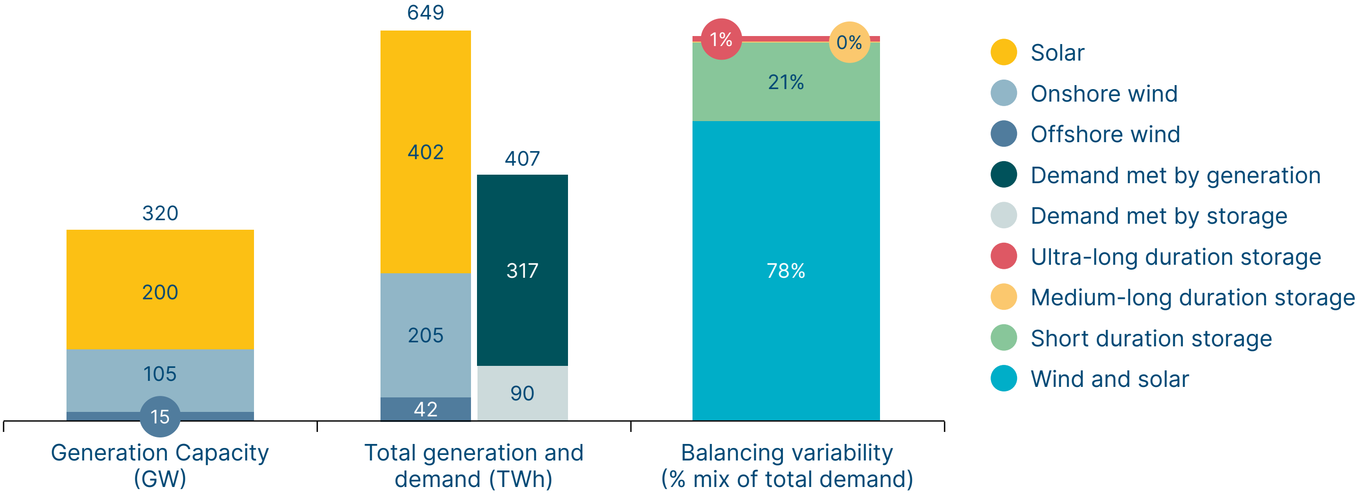
Modelling suggests that 80% of electricity supply and demand would be naturally concurrent, comparable to the High latitude case. Short-term balancing would be required for around 20% of total supply, approximately halfway between the UK and India's system needs, while ultra-long duration balancing (over weeks or months) would be needed for just 1%.

However, there are varying resources by region in Spain with stronger wind resources concentrated in the north and higher solar irradiance in the southern and central regions.[67] Combined, these resources are highly complementary, enabling the high concurrent wind and solar generation (provided that sufficient grid infrastructure is built out).

Exhibit 1.16

Generation and balancing mix results for Mediterranean archetype (Spain Case Study)

GW, TWh, %



Generation

- Solar dominates (~60% of generation) due to high irradiation; wind provides ~40%
- Overbuilding wind and solar is the lowest-cost path to 100% renewables
- Complementary generation helps buffer seasonal lulls (e.g. lower solar and higher wind in winter)

Balancing Mix

- >75% of generation is concurrent; no storage needed during these periods
- Remaining 20% covered by short-duration storage for daily (not seasonal) balancing
- Mediterranean transitions are cheaper than northern ones due to stronger solar resource
- Excess solar must be absorbed via interconnectors, hydrogen, or industrial demand shifting
- Nighttime generation gaps managed with shortduration storage, DSF, and grid optimisation

NOTE: A small share of excess generation is absorbed by storage losses.

SOURCE: Systemiq analysis for the ETC; AFRY (2025), *Hourly Demand Projections.*

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[67] AEMET (Agencia Estatal de Meteorología), *Wind and Solar Energy Resources in Spain*

1.4 Matching power supply and demand: Technologies and business models

A range of technologies and business models can be deployed to address the different balancing challenges outlined above [Exhibit 1.17]. These solutions can be grouped into four broad categories, each addressing specific balancing timeframes, with some overlap between them:

- **Flexible, dispatchable generation**, which can be ramped up or down to complement wind and solar supply.
- **Long-distance transmission infrastructure**, including national, cross-regional and international interconnectors, which can enable geographic balancing by connecting areas with complementary supply and demand patterns.
- **Energy storage technologies**, ranging from batteries for intra-day balancing to long-duration storage solutions such as pumped hydro, compressed air, or hydrogen. A key question is how far the potential role of battery storage can extend given dramatic reductions in battery cost per kWh of storable energy.
- **Demand-side flexibility**, the ability of consumers or distributed assets to adjust electricity consumption or on-site generation in response to external signals, by either increasing or decreasing usage or output. In this analysis, we include thermal energy storage (particularly for heating applications), within this category, as it functions effectively as a form of industrial demand side flexibility**.**

Exhibit 1.17

Balancing technology suite across different durations

			System operation	Short duration (0-8 hours)	Medium-long duration (8-50 hours)	Ultra-long duration (50+ hours)
Grid stability technologies		Synchronous condensers	✓			
		Grid-forming inverters	✓			
Dispatchable generation	Other zero carbon	Hydro, nuclear	✓	✓	✓	🟡
	Fossil	Fossil (or bioenergy) + CCS	✓	✓	✓	✓
		Fossil – low/very low utilisation	✓	✓	✓	✓
		Power-to-X (i.e. H_2)	✓	✓	✓	✓
Interconnection		Accessing complementary weather patterns and time shifting generation	🟡	🟡	🟡	🟡
Energy storage		Pumped hydro	✓	✓	✓	🟡
		Lithium-ion battery	✓	✓	🟡	
		Other technology (i.e. CAES, liquid air, etc.)	✓	✓	✓	🟡
Demand side flexibility		EV (smart charging, V2G)		✓	🟡	
		Heating load		✓		
		Industrial load		✓	✓	

NOTES: Green tick: The technology is well-suited or fully capable of providing the balancing service for the function. Yellow tick: The technology can partially or conditionally support the balancing function, but may have limitations or reduced effectiveness in that timescale. Limited nuclear capacity for flexible ramping considered. Lithium-ion storage is utility-scale and behind-the-metre. Emerging tech includes gravitational storage and molten sands storage and CAES refers to compressed air energy storage. Examples of Power-to-X include the production of H_2 from electrolysis and re-conversion of hydrogen to electricity via gas turbines or fuel cells. V2G means vehicle to grid technology. Heating load includes residential and commercial standard heating needs. Industrial load includes hydrogen electrolysis, where production can be shifted to optimal times.

SOURCE: Climate Policy Initiative for the ETC (2017), *Low-cost, low-carbon power systems.*

1.4.1 Continued use of flexible dispatchable generation

In most current electricity systems, balancing is primarily achieved by adjusting the output of turbine-based dispatchable power plants. Gas turbines can ramp up and down rapidly, coal-fired plants can vary output within a limited range, and dammed and pumped hydropower offers substantial operational flexibility.

As discussed in Section 1.3, a fully wind and solar based system would require significant balancing actions. However, in practice, almost all electricity systems are likely to retain a role for flexible, dispatchable generation within a wind- and solar-dominated mix.

Countries with abundant hydropower resources relative to demand, such as Brazil and Norway, will continue to rely heavily on hydro as a dispatchable low-carbon source. In many other countries, thermal generation is expected to retain a role, particularly during the transition period, to provide firm capacity and system stability when wind and solar output is low.

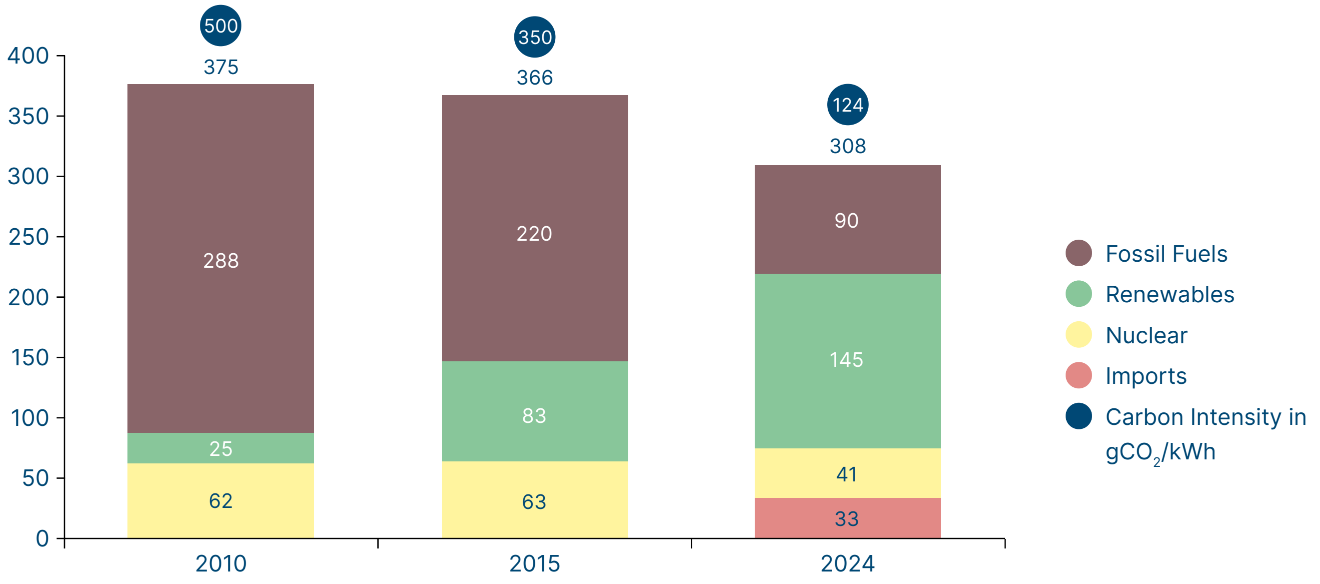
The UK provides a useful example of how flexible, dispatchable gas plants can support the integration of renewables. Since 2010, the carbon intensity of UK electricity has fallen significantly, with a 75% reduction from 500 gCO_2 per kWh in 2010 to 125 gCO_2 per kWh in 2024[68] as shown in Exhibit 1.18. This reduction has been achieved through a shift from coal to gas generation, alongside a rapid increase in wind and solar output, which rose from 25 TWh per annum to 145 TWh per annum over the same period.[69] Importantly, the gas fleet has operated with increasing flexibility, with annual output falling from 290 TWh in 2010 to 90 TWh in 2024, while responding to fluctuations in both wind and solar supply and total electricity demand.[70]

This illustrates an important insight for countries in the early stages of power system decarbonisation. In most systems, wind and solar can grow to over 40% of total electricity generation, with supply and demand managed effectively even without large-scale deployment of the storage technologies discussed below. However, two challenges remain: increasing the operational flexibility of coal generation and progressing from partial to full decarbonisation.

Exhibit 1.18

A shift in the UK power mix has driven a 75% cut in emissions intensity since 2010

UK electricity generation by source and average emissions intensity, 2010–2024
TWh



NOTE: Renewables include wind, biomass, solar and hydro.

SOURCE: Department for Energy Security and Net Zero (2025), *Energy Trends March 2025;* Carbon Brief (2025), *Analysis: UK's electricity was cleanest ever in 2024*. Available at https://www.carbonbrief.org/analysis-uks-electricity-was-cleanest-ever-in-2024/. [Accessed January 2025].

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[68] Carbon Brief (2025), *Analysis: UK's electricity was cleanest ever in 2024*. Available at https://www.carbonbrief.org/analysis-uks-electricity-was-cleanest-ever-in-2024/#:~:text=The UK's%20electricity%20was%20the,two%2Dthirds%20in%20a%20decade. [Accessed February 2025].

[69] Department for Energy Security and Net Zero (DESNZ) (2025), *Energy Trends March 2025*.

[70] Systemiq analysis for the ETC (2025); Based on hourly generation profiles from NESO, *Historic GB Generation Mix*. Available at https://www.neso.energy/data-portal/historic-generation-mix/historic_gb_generation_mix. [Accessed January 2025].

Increasing the operational flexibility of coal generation

Gas generation is inherently flexible, with combined-cycle gas turbines (CCGTs) capable of rapid ramping, and open-cycle gas turbines (OCGTs) offering even greater flexibility but at a lower efficiency. Coal plants are technically less flexible, but a range of emerging technologies can extend both the range and speed at which they can vary output [Box C]. Enhancing the flexibility of coal plants, and operating them at progressively lower utilisation rates, could and should play a central role in enabling coal-dependent power systems, particularly in China and India, to achieve progress in power system decarbonisation.

Critically, any investment in coal plant flexibility must be carefully assessed to avoid reinforcing carbon lock-in or displacing lower-carbon alternatives. Additionally, increasing the flexibility of systems should not act as a barrier to eventual phase out, nor justify any new-build. Complementary policy measures such as carbon pricing also remain critical for ensuring that externalities are reflected in dispatch decisions, helping to reduce coal utilisation in line with efficient, lower-emissions system operation.

BOX C

Coal generation has the potential to run flexibly under certain conditions

While coal generation is typically less flexible in terms of varying output during the days or weeks, modifications to coal plants can enable them to run more flexibly. From a technical perspective, running coal plants more flexibly requires changes across three key features [Exhibit 1.19]:

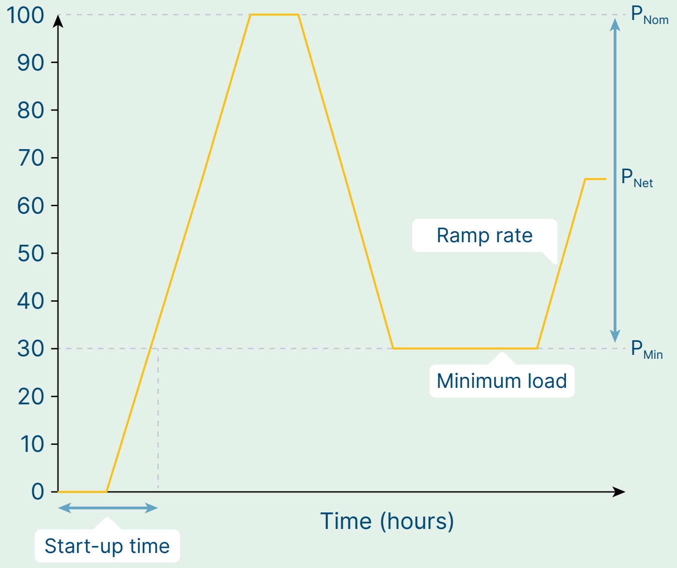
- **Start-up time:** Rapid start-up time, i.e. the time it takes for a plant to turn on, allows plant to reach its minimum level of operation quicker. However, this can add greater thermal stress, and there are limitations to start-up time reductions.
- **Minimal load:** A lower minimal load means the plant can stably produce at lower outputs. However, this typically results in lower efficiency and there are also technical limitations when operating at minimal load.

Exhibit 1.19

The flexibility of conventional power plants is dependent on three key factors

Qualitative representation of key flexibility parameters of a power plant

Power, % nominal capacity



	Hard coal (Commonly exported)		Lignite coal (Generally mined/ used domestically)	
	Common	Best in class	Common	Best in class
Minimum load [% P_{Nom}]	40–50%	25–40%	50–60%	35–50%
Average ramp rate [% P_{Nom} per min]	1.5–4% (i.e. 15–40 MW/min for 1 GW plant)	3–6% (i.e. 30–60 MW/min for 1 GW plant)	1–2% (i.e. 10–20 MW/min for 1 GW plant)	2–6% (i.e. 20–60 MW/min for 1 GW plant)
Hot start up time [min] or [h]	2.5–3 h	80 min –2.5 h	4–6 h	1.25–4 h
Cold start-up time [min] or [h]	5–10 h	3–6 h	8–10 h	5–8 h

NOTE: P_{Nom} = Nominal power capacity

SOURCE: Systemiq analysis for the ETC; Agora (2017), *Flexibility in thermal power plants.*

- **Ramp rate:** This is the speed at which net power feed-in can be adjusted, which must be fast to match variations in renewable generation. A higher ramp rate allows the plant to adjust output more rapidly. Rapid changes can result in thermal stress, so there are technical limitations to this speed.

Typically, hard coal plants are more flexible than lignite.

The retrofits required to increase flexibility entails an additional cost, which also varies by type of coal plant (it is typically more expensive for older, less efficient plants). In Europe, retrofit packages for coal plant flexibility have been in the range of $60–80 million for 600 MW projects, equivalent to ~10% of already spent CAPEX for the plant.[71] This type of investment could initially add ~$2 per MWh to the cost of delivering electricity from the plant; however, the additional cost would largely be offset by OPEX reductions due to efficiency improvements in the plant, therefore making retrofits broadly cost-neutral over the long run.[72]

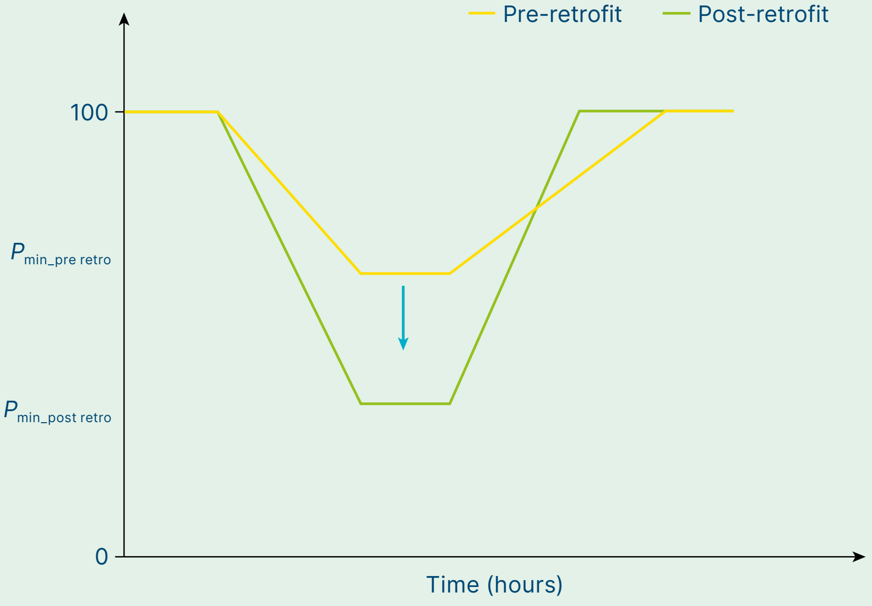
In Germany, the Neurath Block E plant saw light retrofits which extended the life and increased efficiency, as well as modified the technical parameters, which enabled cost-effective substantial increases in flexibility [Exhibit 1.20]. Overall, coal plants are already providing significant flexibility in Germany, operating in 15-minute intraday markets.[73]

The ability of coal to run flexibly means as renewables grow, balancing can be met initially with existing fossil generation running in a more flexible manner. Previous ETC analysis suggests that India could achieve ~30% of wind and solar generation with no new fossil generation capacity,[74] while other reports highlight the value of coal running flexibly in Denmark and Indonesia:

Exhibit 1.20

Coal: At the German Neurath Block E plant, light retrofits have enabled cost-effective substantial increases in flexibility

Load curves for pre- and post-retrofit of German Neurath Block E coal plant
% of nominal capacity



€70 million (~10% of initial project CAPEX) was invested into retrofitting a 600 MW turbine within the lignite plant over **2.5 months** (~120 $/kW).

This upgraded plant control technology and certain components (i.e. condenser and cooling tower) which:

- Extended life of 35-year-old plant by 10 years
- Increased efficiency by 0.6%
- Reduced minimum load from 70% to 48% (420 MW→290 MW)
- Increased ramp rate from 0.7%/min to 2.4%/min (4.2→ 14.2 MW/min)
- Shortened start-up time from 4 ¼ hrs to 3 ¼ hrs

SOURCE: Reused with permission from Agora (2017), *Flexibility in thermal power plants.*

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[71] Agora Energiewende (2017), *Flexibility in Thermal Power Plants: With a Case Study of the German Power Market*.

[72] Cost of coal plant assumes CAPEX costs of $1200 per kW, a typical 600 MW coal plant may cost $720 million. This could range from $700 per kW, or $420 million for 600 MW in China to $2000 per kW, or $1200 for 600 MW in Japan. Retrofit costs can range from $50–200 million depending on geography and extent up upgrades. See: IEA (2018), *Status of Power System Transformation*; Agora (2017), *Flexibility in thermal power plants*.

[73] Agora (2017), *Flexibility in thermal power plants*; Ember (2024), *Electricity Data Explore*. Available at https://ember-energy.org/data/electricity-data-explorer/. [Accessed February 2025].

[74] ETC (2021), *Making Clean Electrification Possible: 30 Years to Electrify the Global Economy*.

- **TERI's study on India**[75] showed that 32% of electricity could be met by variable renewables by 2030 (up from 10% in 2023), and that flexibility could be met principally with flexibility from conventional generators, in particular the coal and hydro fleet, as well as an increasing role for battery storage (60 GW in 2030). The study laid out that India's existing coal plants could be retrofitted to operate more flexibly, by:
    - **Reducing minimum load** from 55% to 30–40%
    - **Increasing ramp rate per plant** of 1% per m to 2% per m
    - **Increasing all-India ramp speed** capability to 700 MW per min
    - **Enabling 16 GW of capacity to "two-shift"** - that is, to start up and shut down multiple times per week (up to four starts), depending on system needs.
- **An IESR study for Indonesia** highlights how the country's relatively young coal fleet (with an average age of just nine years) can and should be retrofitted to operate more flexibly. The study identifies three key priorities for retrofit: reducing minimum load levels from 50% to 30%, increasing ramp rates to twice their current levels, and shortening start-up times from 2–10 hours to 1.3–6 hours.[76]
- **Denmark**'s coal fleet is already playing a flexible role. Despite being a low-gas, low-hydro system, Denmark has reached nearly 70% wind and solar generation annually without large-scale storage development, by combining high levels of interconnection (9 GW, ~25% of capacity) with more dynamic operation of existing thermal assets. In 2024, wind and solar were running alongside 8% coal, 21% bioenergy, and a heavily interconnected system.[77]

The main challenge is ensuring the correct planning and market design to reward existing plants running flexibly while ensuring they play a declining role in the system. Implementing appropriate mechanisms to reward flexibility will be essential, including enhancing long-term planning processes to identify coal plant transitions to run more flexibly, as well as reforms to market agreements such as renegotiation of contracts to enable lower running hours.

Progressing from partial to full system decarbonisation

Operating gas or coal plants flexibly can play a critical role in the early stages of power sector decarbonisation. However, achieving full decarbonisation will require additional measures, including either:

- The addition of CCS technologies to gas or coal plants, enabling them to operate with near zero-emissions; or
- The conversion of gas turbines to run on low-carbon hydrogen, with hydrogen produced via electrolysis from wind and solar generation or via the steam methane reforming of natural gas with CCS. Both hydrogen combustion in gas turbines and hydrogen storage, such as in salt caverns, are technically feasible and are discussed in more detail in Section 1.5.5.[78]

The relative economics of these two approaches, alongside a third option in which a small volume of unabated gas remains in the system and is offset by carbon dioxide removal, as discussed in Section 1.5.5 and also shown in Exhibit 1.2 below.

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[75] TERI (2020), *Renewable power pathways: modelling the integration of wind and solar by 2030;* Government of India (2023), *A roadmap for achieving 40% technical minimum load.*

[76] IESR (2020), *Understanding flexibility of thermal power plants: Flexible coal power generation as a key to incorporate larger shares of renewable energy.*

[77] Ember (2024), *Electricity Data Explorer.* Available at https://ember-energy.org/data/electricity-data-explorer/. [Accessed February 2025].

[78] While the continued use of gas or coal plants would imply that the system was not 100% wind and solar dependent, if the gas turbine fleet were entirely converted to burn hydrogen, a 100% wind and solar system is theoretically possible though still unlikely in practice due to the high costs associated with hydrogen storage and production, as noted in Section 1.5.3.

Exhibit 1.21

Flexibility of different generation technologies

Technology	Flexibility Assessment	Real-World Examples
Hydropower	**Reservoir Hydropower - High flexibility:** Particularly for reservoir-based systems that can rapidly respond to demand fluctuations. Run-of-river hydro has minimal flexibility. **Pumped Hydropower - Very high flexibility:** Ideal for short- to medium-duration balancing. Fast response times and ability to absorb excess wind and solar make it highly versatile.	**Norway:** Reservoir-based hydropower provides rapid-response balancing, supporting both domestic needs and neighbouring grids. **Austria & Spain:** Pumped hydro is widely used for intra-day balancing and integrating solar generation. Plans to expand storage capacity are underway.
Nuclear	**Moderate flexibility:** Technically feasible but constrained by economic and operational factors. Load-following capabilities depend on reactor design.	**France:** Nuclear reactors operate with limited flexibility and have adjusted output to follow demand patterns and accommodate renewables.
Coal	**Low-to-moderate flexibility:** Requires technical retrofits for faster ramping, but flexibility improvements reduce efficiency.	**Germany:** Certain coal-fired plants have been adapted for flexible operation, adjusting output to accommodate fluctuations in renewable generation.
Combined Cycle Gas Turbines (CCGTs)	**High flexibility:** Capable of fast ramping when appropriately configured and well-suited for balancing variable renewables. Can be modified for hydrogen co-firing.	**UK & US:** New CCGT plants are being designed with hydrogen-ready turbines and enhanced cycling capabilities, enabling flexible backup while supporting long-term decarbonisation.
Open Cycle Gas Turbines (OCGTs)	**Very high flexibility:** Simple-cycle design allows for extremely fast ramp-up and start times, ideal for peaking and contingency support.	**Japan & Thailand:** Used for peak demand support with growing interest in hydrogen retrofits for zero-carbon backup.

SOURCE: Systemiq analysis for the ETC; Statnett (2021), *Balancing the Nordic Power System with Reservoir-Based Hydropower;* EDF (2022), *EDF Nuclear Flexibility to Support France's Energy Transition;* Agora Energiewende (2021), *The Flexibility of Coal-Fired Power Plants in Germany;* GE Vernova (2024), *Hydrogen-Fueled Gas Turbines and Flexibility Improvements in CCGT Plants;* Reuters (2024), *Japan's JERA to invest $32 billion in LNG, renewables and new fuels over decade.* Available at https://www.reuters.com/sustainability/japans-jera-invest-32-bln-lng-renewables-new-fuels-over-decade-2024-05-16/. [Accessed December 2024].

1.4.2 Long distance and international transmission

The larger the geographical area covered by an interconnected electricity system, the lower the variability in wind and solar supply and power demand is likely to be. This is particularly true when different regions experience uncorrelated patterns of generation and consumption. As a result, long-distance transmission infrastructure is a critical enabler of balancing in wind and solar dominated power systems, both within large countries and across national borders. While high-voltage direct current (HVDC) lines are typically used for very long-distance or cross-border links due to their lower transmission losses, high-voltage alternating current (HVAC) interconnections are more abundant and often easier to develop, particularly for shorter distances or within well-meshed networks. This applies both within large countries and across national borders.

The ETC has conducted a detailed analysis of the potential role of long-distance transmission, with a particular focus on international interconnection. ETC Insights briefing *Connecting the World: Long-Distance Transmission as a Key Enabler of a Zero-Carbon Economy* sets out the key findings from this work. Long-distance transmission can provide two distinct benefits:

- Enabling low-cost renewable electricity from resource-rich areas to be delivered to demand centres that would otherwise rely on more expensive local generation.
- Connecting regions with uncorrelated wind and solar supply and demand profiles, reducing the need for storage by smoothing variability across time and space. For instance, west-to-east transmission links could allow evening electricity demand in India to be met by solar power from regions where the sun is still shining, such as the Middle East. Similarly, north–south connections can bridge complementary wind and solar profiles, as in the case of North Sea wind and North African solar.

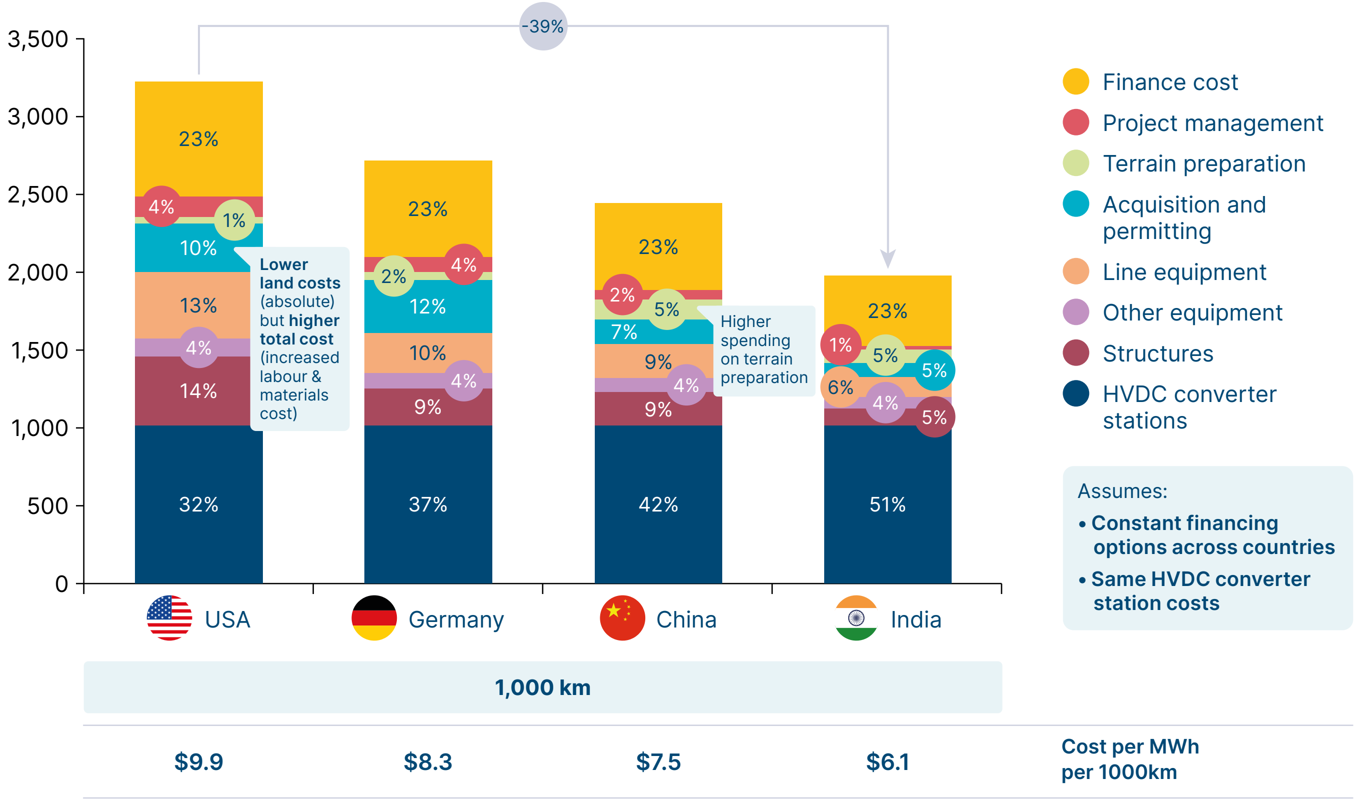
The economics of either of these business rationales will depend on the cost of long-distance transmission compared with the benefits which result. These costs vary significantly between countries and between different types of transmission line technology (e.g. subsea versus overground versus underground) but in many cases costs for HVDC projects could range between 3–10 $ per MWh per 1000 km.[79] This means long-distance transmission could be a cost-effective enabler of high wind and solar shares. Exhibit 1.22 below shows the cost range for 1,000 km projects in key geographies (noting that project costs spread over longer distances, e.g., 4,000 km, could reach the lower bound cost of $3 per MWh per 1000 km).

Exhibit 1.22

HVDC cable costs vary substantially across countries

Estimated cost breakdown of a HVDC power line

Illustrative project: 1000 km, 2024, 2 GW, 400 kV, 85% utilisation rate, Aerial line, $



NOTE: Project management, terrain preparation, acquisition and permitting, line equipment, other equipment; Structures come from BNEF GridVal model. HVDC converter stations assumed to cost $1.1 bn; Finance assumed to cost 5% per annum with 100% of project cost to be paid back over 10 years. New England values used for USA; lifetime of cable assumed to be 50 years, with MWhs discounted at a rate of 3.5% per annum starting from the first year of generation; 85% utilisation rate equivalent to 2GW power being sent 7450 hours of the year.

SOURCE: BNEF (2024), *GridVal 1.0;* ETC calculations based on stakeholder engagements.

China is already deploying HVDC technology on a large scale. It has a very extensive network of ultra-high-voltage (UHV) network of over 30 lines, with the largest being the Changji-Guquan Ultra High Voltage Direct Current (UHVDC) transmission line, which spans over 3,300 km, has a voltage of 1,100 kV, and a transmission capacity of 12 GW.[80] Within Europe, multiple international connectors have been developed - in total, Europe currently has over 400 interconnectors across 39 national systems (for instance from the UK to Norway, Ireland, France, Belgium and the Netherlands), though in most cases these are relatively short distance compared with the longest Chinese lines.[81] Another major example is Brazil, which operates extensive HVDC lines connecting distant hydro-rich high Latitude regions to demand centres in the south, part of a growing network across Latin America enabling regional balancing.[82]

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[79] Assuming over 1,000 km with high utilisation rates, e.g., 85%, for above ground projects, $3 per MWh per 1000 km for a 4,000 km overground line in India, to $10 per MWh per 1,000 km for a 1,000 km line in New England, USA. See Systemiq analysis for the ETC.

[80] NS Energy (2020), *Changji-Guquan UHVDC Transmission Project.*

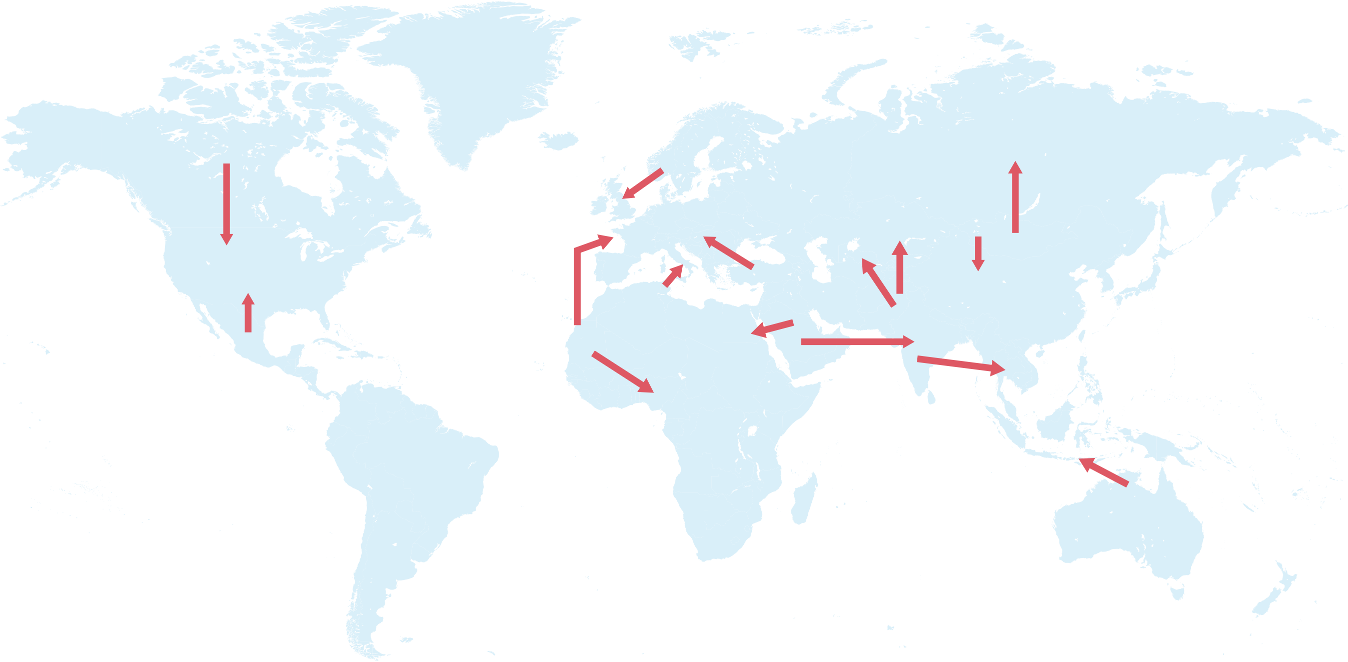
[81] Ember (2024), *Clean flexibility is the brain managing the clean power system.*

[82] ONS (2023), *Brazil's Electric System Development Plan: Transmission Expansion and HVDC Integration.*

Our analysis has identified several potentially attractive applications for international interconnection. Overall, the modelling results suggest there is very large global potential for cross-border interconnection, with a small number of high potential links [Exhibit 1.23] having potential to deliver by 2050: 15% of global power demand, 1.8 Gt per annum carbon reductions (equal to 13% of global power sector emissions), and $100 billion of savings per year.[83]

Exhibit 1.23

High potential "major projects" for international interconnection



NOTE: Top 15 lines based on results across all metrics amended for political feasibility – Trading power between allied nations, not crossing excessive country borders. Largest line shown = Mongolia to Russia at 895 TWh, smallest shown Mexico to USA at 170 TWh.

SOURCE: Systemiq analysis for the ETC.

Both long-distance transmission links within large countries and between countries can face significant implementation barriers, relating to supply chain constraints, opposition to infrastructure building, planning delays, or the complexities of agreeing international deals.[84] Some of these can be partly overcome via improvements in grid technology which are discussed in Chapter 2 and key policy actions required to remove barriers are discussed in Chapter 4.

1.4.3 Energy storage

A wide range of technologies can provide energy storage across the full spectrum of required durations, each with distinct advantages and trade-offs, as outlined in Exhibit 1.24.

The relative economics of these technologies are explored in detail in Section 1.5.2 and will continue to evolve with ongoing technological progress and operational learning. It is neither possible nor necessary to predict in advance the precise optimal mix of technologies that will be deployed. However, Exhibit 1.25 presents the storage solutions which are likely to play a significant role at different durations and project scales.

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[83] The top 10 lines across each category deliver these level of benefits, combining results across all categories would result in substantially greater benefits.

[84] NREL (2024), *Barriers and Opportunities To Realize the System Value of Interregional Transmission*

Exhibit 1.24

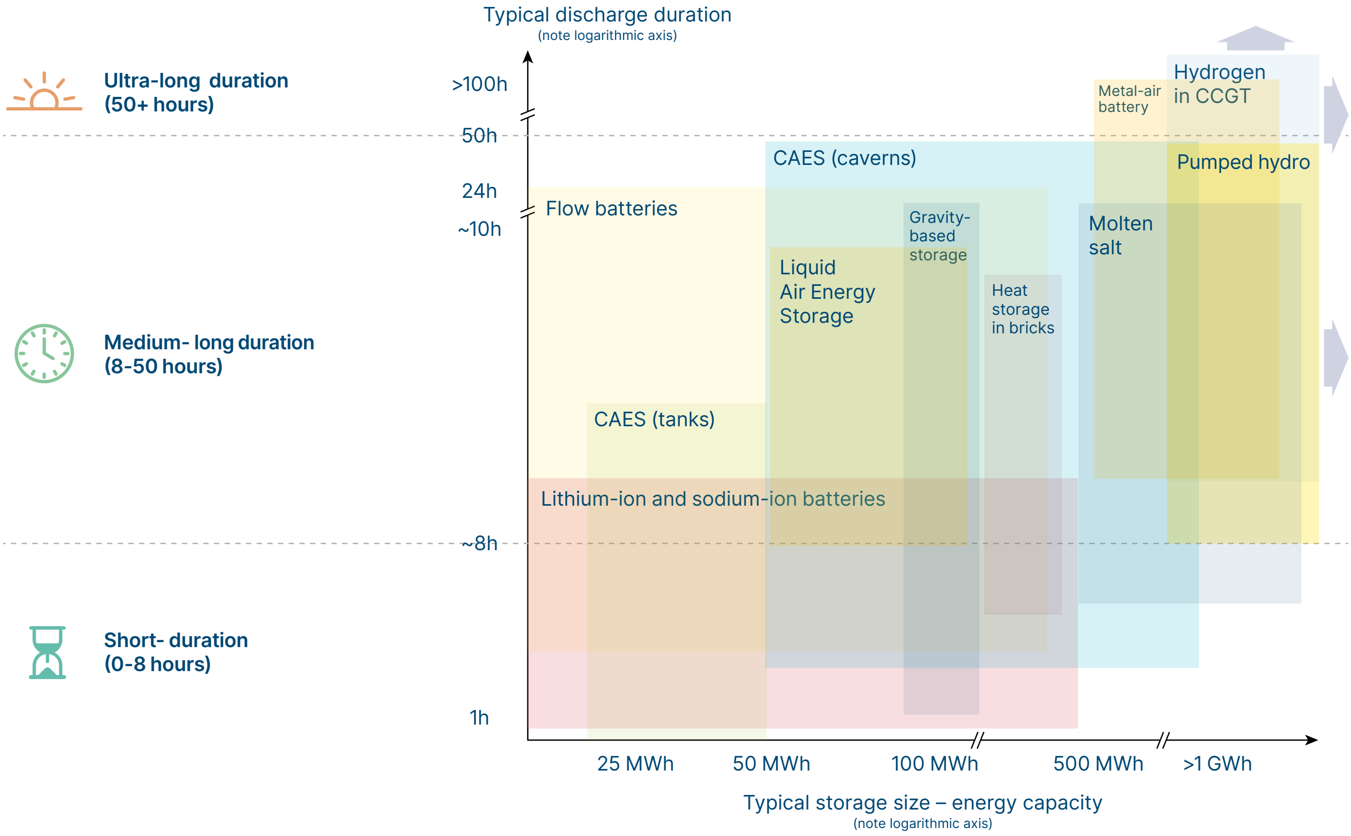
Medium-long and ultra-long duration (8–50+ hours) energy storage: Diverse technologies, each with trade-offs

	Definition	Duration	Strength	Weakness
Lithium-ion Batteries	Electrochemical storage using lithium ions to move between electrodes during charge/discharge.	1–12 h	High efficiency (~85–95%), proven scalability, declining costs.	Limited lifespan (~10–15 years), raw material constraints, higher degradation over long-duration cycling.
Sodium-ion Batteries	Electrochemical storage using sodium ions to transfer charge between cathode and anode materials during charge and discharge cycles.	1–12 h	Abundant and low-cost raw materials, better low-temperature performance than lithium-ion, emerging scalability	Lower energy density than lithium-ion, still at early commercialisation stage with limited long-duration cycling data.
Flow Batteries	Using liquid electrolytes stored in external tanks to facilitate energy storage and discharge.	8–12 h	Scalable, good cycle life, flexible siting.	Lower energy density, expensive materials.
Compressed Air Energy Storage	Compressing and storing air underground, then expanding it to generate electricity.	8–24 h, up to multi-day	Using existing underground formations, scalable, long-duration storage.	Limited by suitable geology, efficiency losses.
Liquid Air Energy Storage	Cooling air to a liquid state, storing it, and later expanding it into gas to drive a turbine.	8–24 h	High energy density, no geological constraints.	Lower efficiency than alternatives, requires liquefaction energy.
Gravity storage	Lifting heavy masses (e.g., concrete blocks, water) to store potential energy, then releasing them to generate electricity.	4–24+ h	Durable, low degradation, and lower environmental impact than other long-duration storage	Still in early commercialisation, requires large structures, efficiency varies (~60–80%)
Pumped Hydro Storage	Using gravitational potential energy by pumping water to an elevated reservoir and releasing it through turbines when needed.	8–24 h, up to multi-day	Proven technology, high efficiency, large-scale storage.	Geographically constrained, high upfront cost.
Metal-Air Batteries e.g., Iron-Air	Using metal oxidation/reduction reactions to store and release energy, offering multi-day storage.	24–100 h	Low cost materials, long discharge times.	Lower efficiency (~50–60%), slow charge/discharge.
Molten Salt and Thermal Storage	Storing thermal energy in molten salts or solid-state materials for later conversion to electricity.	10–100 h	Efficient thermal storage, integrates well with CSP.	Requires high-temperature storage, complex system integration.
Hydrogen storage	Producing H_2 via electrolysis, storing it (e.g., in salt caverns), and reconverting it to power via fuel cells or turbines.	100+ hours (seasonal)	Very high energy density, enables large-scale, seasonal storage.	Hydrogen production cost and infrastructure challenges, safety, low round-trip efficiency.

SOURCE: Oxford Institute for Energy Studies (2024), *Powering the Future: Energy Storage in Tomorrow's Electricity Markets;* Khan et. al (2024), *Recent Advancements in Energy Storage Technologies and Their Applications.*

Exhibit 1.25

Energy storage technologies span a range of sizes and durations



NOTE: Simplified visual description for improved readability. CAES refers to compressed air energy storage. CCGT refers to combined cycle gas turbine.

SOURCE: BNEF (2024), *2024 long-duration energy storage cost survey;* Pacific Northwest National Laboratory (2023), *Energy Storage Cost and Performance Database;* IEA (2024), *ETP Clean Energy Technology Guide.*

Short duration: the dominance of batteries

Short duration storage systems (ranging from 0 to 8 hours) are essential for managing hourly and day-to-day fluctuations in renewable electricity supply and for providing critical ancillary services such as frequency regulation and rapid response to maintain grid stability. Among the various technologies capable of delivering these services, lithium-ion batteries – also the dominant battery in EVs - have become the predominant choice. This dominance is attributed to several key factors:

- Lithium-ion batteries offer high round-trip efficiencies, typically ranging between 85% and 95%,[85] facilitating effective energy storage and release. They also possess the capability to charge and discharge quickly, making them well-suited for applications requiring immediate power delivery.
- Unlike alternatives such as compressed air or pumped hydro storage, which often necessitate extensive engineering and site-specific infrastructure, lithium-ion batteries benefit from modular and scalable designs. The advent of containerised solutions, where battery packs and management systems are integrated into standard shipping containers, has further streamlined deployment processes, allowing for rapid installation and flexibility in various locations.
- Over the past decade, the cost of lithium-ion battery packs has seen a dramatic decline of 87% from $872 per MWh in 2012 to $115 per MWh in 2024.[86] This substantial decrease has been driven by advancements in manufacturing processes, economies of scale, and improvements in battery chemistry, enhancing the economic viability of lithium-ion batteries for large-scale energy storage applications.

These attributes collectively position lithium-ion batteries as a leading solution for short-duration energy storage needs in modern power systems.

[85] New York State Energy Research and Development Authority (NYSERDA) (2024), *Energy Storage System Performance Impact Evaluation.*

[86] BNEF (2025), *LCOE Data Viewer.*

This fall in price reflects technical innovation, the achievement of large manufacturing economies of scale and learning curve effects:

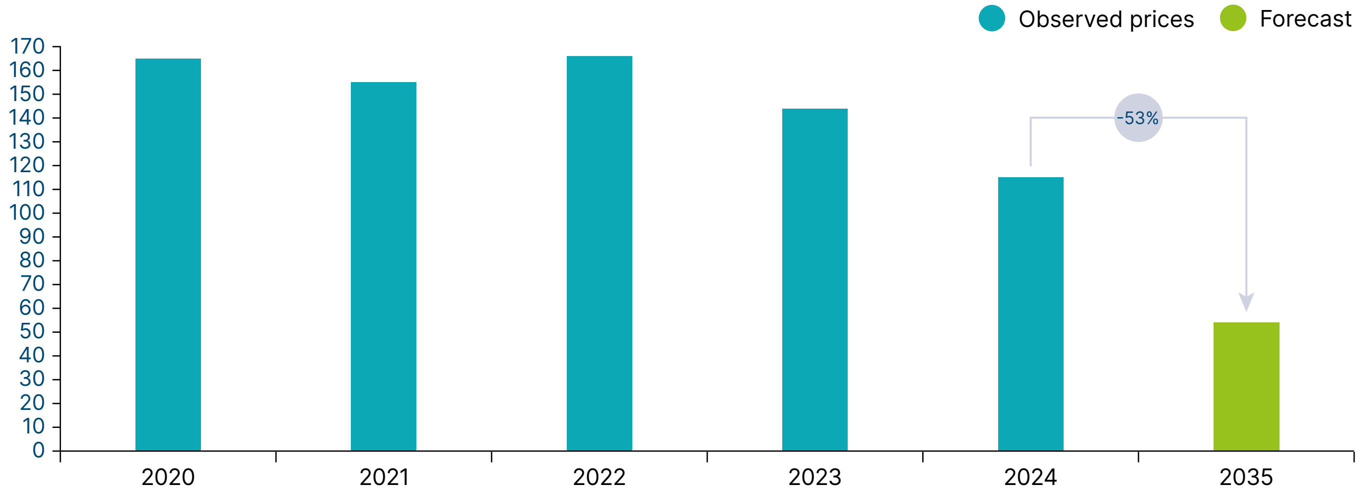
- **Adoption of lithium iron phosphate (LFP) chemistries:** Since around 2019, the rapid adoption of LFP battery chemistries has contributed to cost reductions. LFP batteries are less expensive than the previously dominant Nickel Manganese Cobalt (NMC) chemistries due to the absence of costly materials like cobalt and nickel. Additionally, LFP batteries offer longer lifespans, with some manufacturers guaranteeing up to 10,000 charge-discharge cycles without significant degradation.[87] This longevity is crucial for applications requiring daily or more frequent cycling.
- **Economies of scale in China:** China has achieved substantial economies of scale in battery manufacturing. By the end of 2023, China's battery manufacturing capacity reached approximately 2.2 TWh, nearly double the global demand projected for 2024.[88] This overcapacity has led to intense price competition and significant cost reductions.
- **Projected future cost declines:** BNEF forecasts a 46% reduction in battery pack prices between 2025 and 2035. In China, LFP pack prices are already as low as $66 per kWh, and further reductions are anticipated, potentially reaching $45 per kWh by 2035.[89]
- **Sodium-ion batteries** have also emerged as a promising alternative to lithium-ion. Sodium-ion offers comparable power performance and thermal stability to LFP chemistries, while relying on more abundant raw materials.[90] While current cycle life and energy density are lower than leading lithium-based chemistries, recent cell-level data indicates energy densities of 120–160 Wh per kg which will be sufficient to support deployment in stationary applications.[91] While costs for sodium-ion cells are currently higher than lithium-ion, due to these technologies not benefitting from the economies of scale that lithium-ion battery producers have developed, sodium-ion batteries will decline in price due to the high levels of manufacturing expected from China's battery producers.[92] Sodium will also become particularly important if lithium prices rise from the current low level, which is more than 80% below the peak of early 2023.[93]

Given the inherent advantages of batteries, and the prospects for further cost reduction, it is highly likely that batteries will dominate the short duration storage market.

Exhibit 1.26

As highlighted by BNEF, lithium-ion battery prices expected to halve by 2035

BNEF Lithium-ion battery pack price outlook
($/kWh, real 2024)



SOURCE: BNEF (2025), *Levelized Cost of Electricity Update 2025.*

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87 Ecotree Lithium, *LiFePO4 Battery Cycle Life and Durability*. Available at https://ecotreelithium.co.uk/news/lifepo4-battery-cycle-life-and-durability. [Accessed April 2025].

88 PV Magazine (2025), *The battery boom of 2024 as one of five trends in renewables*. Available at https://www.ess-news.com/2025/01/02/the-battery-boom-of-2024-as-one-of-five-trends-in-renewables/. [Accessed February 2025].

89 BNEF (2025), *Levelised Cost of Electricity Update 2025.*

90 BNEF (2024), *Sodium-Ion Batteries: Technology and Cost Outlook.*

91 PV magazine (2024), *New sodium-ion developments from CATL, BYD and Huawei*. Available at https://www.pv-magazine.com/2024/11/28/new-sodium-ion-developments-from-catl-byd-huawei/. [Accessed January 2025].

92 CRU (2024), *Sodium-ion batteries will take time to become cost-competitive.*

93 Nasdaq (2025), *Lithium Market Update: Q1 2025 in Review.*

Medium-long duration storage

The optimal balance of different technologies is less clearly defined at storage durations above eight hours. This reflects both a wider range of potentially competitive technologies and the fact that limited deployment has been required to date, since fossil fuel plant flexibility can meet medium-long duration balancing needs at low to moderate levels of wind and solar penetration. However, large-scale deployment of medium-long duration storage will become increasingly important as wind and solar penetration continues to rise.

Batteries are technically capable of meeting medium-long duration storage needs, since they can be charged and discharged at slower rates than their maximum power capacity. However, the historically high capital cost per kWh of storage has made them uneconomic for applications with limited charge/discharge cycles, such as those required for medium-duration balancing, compared to their use in short-duration energy shifting or ancillary services. As battery costs continue to fall, there is an open question as to how far up the duration curve batteries can become cost-competitive [see Box D].

Several alternative technologies are likely to play a significant role in medium-long duration storage. These include:

- **Compressed air energy storage (CAES),** which stores energy by compressing air into geological formations (such as salt caverns) or engineered vessels. Most current CAES systems rely on using the compressed air to support natural gas combustion in peaker turbines, improving efficiency but maintaining a carbon footprint. Fully adiabatic CAES systems, which aim to eliminate gas combustion entirely, are under development but not yet commercially mature.[94]
- **Pumped hydro storage,** typically deployed in large-scale projects. Other gravity-based systems are also being explored, including technologies that lift and lower solid masses such as concrete blocks or heavy weights in mine shafts or towers, converting potential energy to electricity. While less mature than pumped hydro, these systems may offer greater siting flexibility and modularity.
- **Alternative battery chemistries,** such as vanadium redox flow batteries and iron-air batteries. Flow batteries, such as vanadium redox, are well-suited to medium-long duration applications and have been deployed primarily at small scale due to their lower energy density and higher balance-of-system costs. Iron-air batteries, which operate via reversible oxidation, are currently being developed for large-scale, long-duration storage due to their projected low cost per kWh and suitability for multi-day storage.
- **Thermal energy storage,** where materials such as bricks or molten salt are heated using surplus electricity and later discharged either as heat or converted back to electricity via a steam turbine. In most current applications, stored energy is primarily used to provide industrial or district heat, where round-trip efficiency is less critical. However, systems that reconvert heat to power – such as those using steam turbines or thermophotovoltaic cells – are also available, though with lower overall efficiency. Other “power-to-heat” and “heat-to-power” configurations are also under development, with use cases spanning from industrial decarbonisation to flexible grid support.

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[94] Siemens Energy (2024), *CAES – Compressed Air Energy Storage Systems.*

The cost competitiveness of these technologies, both in absolute terms and relative to lithium-ion batteries, depends on a combination of capital cost per kWh stored and round-trip efficiency, as considered in Section 1.6. Their potential role will also depend on:

- Geographical constraints, with some technologies requiring specific physical conditions (e.g., underground caverns for CAES or elevation differences for pumped hydro).
- Project scale and complexity, as technologies like pumped hydro and CAES typically require larger capital investment, longer development timelines, and are highly dependent on planning and permitting processes, compared with the more modular and rapidly deployable nature of battery systems.

BOX D

Falling battery costs are extending the role of lithium-ion into longer duration storage

The rapid decline in lithium-ion battery prices has challenged the long-held assumption that batteries are unsuitable for long-duration energy storage. Historically, lithium-ion systems were considered uneconomical beyond 4–6 hours due to the high marginal cost of stacking additional battery cells, with available revenues from energy arbitrage or ancillary services insufficient to justify the investment. While there were no inherent technical barriers to longer durations, developers could always install more capacity, doing so was typically cost-prohibitive.

However, recent capital cost reductions, improved battery chemistries, and more integrated system designs are enabling a new generation of lithium-ion systems to compete in long-duration applications. For example, manufacturers such as CATL, now marketing battery architectures specifically designed for 8+ hour durations. CATL's "Tener" cell-to-pack battery is one such example of commercially available systems with longer storage durations and lower balance-of-system costs, making lithium-ion viable well beyond short-duration use cases.

Real-world deployments underscore this shift:

- In California, the Tumbleweed (69 MW per 552 MWh) and Goal Line (50 MW per 400 MWh) lithium-ion systems were selected in long-duration procurements, signalling their economic viability in multi-hour balancing markets.[95]
- In Australia, RWE's Limondale battery storage (400+ MWh, 8-hour) secured a government-backed tender, demonstrating investor confidence in lithium-ion for long-duration storage applications.[96]

These developments confirm that lithium-ion batteries have no strict technical limit on duration; increasing energy-to-power ratios is simply a question of adding more cells. In the past, this was economically challenging, but it is now increasingly viable as both technology and market revenues improve. Today, the real constraint is no longer technical but economic, capital cost, degradation, and available revenue streams determine whether it makes sense to optimise a project for 4 hours, 8 hours, or even longer durations.

As market designs evolve and system needs shift toward daily and multi-day balancing, lithium-ion's flexibility, modularity, and declining costs position it as a cornerstone technology for long-duration storage, especially where geographical or permitting constraints limit alternatives such as pumped hydro or CAES.

Ultra-long duration storage

As discussed in Section 1.4.1, ultra-long duration flexibility can be delivered through dispatchable thermal turbine-based plants. These can be made to be low carbon either by adding CCS to continued natural gas (methane) combustion or by switching from methane to hydrogen as the fuel source. In the former case, the energy storage system is effectively the existing natural gas storage infrastructure, which can support seasonal balancing. In the latter case, hydrogen produced via electrolysis during periods of renewable generation surplus is stored for later use in gas turbines or fuel cells.

The primary option for hydrogen storage is in underground salt caverns. Analysis suggests that several of the countries expected to require large-scale ultra-long duration storage possess sufficient salt cavern capacity to meet anticipated needs. For example, countries with the highest potential include the United States (particularly the Gulf

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[95] California Community Power (2022), *Seven California Community Power Members Contract for 69 Megawatts of Long Duration Energy Storage.*

[96] RWE (2023), *RWE successful in Australian tender with long duration battery storage project*. Available at https://www.rwe.com/en/press/rwe-renewables/2023-05-01-rwe-successful-in-australian-tender-with-long-duration-battery-storage-project/. [Accessed February 2025].

Coast),[97] Germany, the United Kingdom, and Canada.[98] Other countries such as China, France, and the Netherlands also have viable formations, though development remains at an earlier stage.[99] These caverns are typically located in regions with historical use for natural gas storage and are now being assessed or repurposed for large-scale hydrogen applications. It should be noted that there are contested use cases for salt caverns, as they can be used for hydrogen, but also CCS and CAES, meaning that technologies may have to compete to secure the a cavern in a particular location.

An alternative technology for ultra-long duration storage is iron-air batteries, which exploits the chemical reaction between iron and oxygen. During discharge, iron is oxidised to form iron oxide (releasing energy), and during charging, the iron oxide is reduced back to iron (absorbing energy).[100] While round-trip efficiency is relatively low, this may be offset by very low capital costs, due to the use of abundant and low-cost materials such as iron, air, and water.

1.4.4 Demand side flexibility

Demand side flexibility (DSF) refers to the ability of consumers or distributed assets to adjust electricity consumption or on-site generation in response to external signals, by either increasing or decreasing usage or output. While commonly used to reduce demand during peak hours, DSF can also help absorb excess renewable supply or support grid stability through upward load shifts or generation increases. By reducing the need for energy storage, DSF can lower the overall cost of balancing within a high wind and solar power system.[101] It can also reduce the required capacity and cost of networks, and is therefore also discussed in Chapter 2, which considers network investments needed to support rising electricity demand.

Significant opportunities exist for DSF in households and commercial buildings, those primarily addressing the short duration balancing challenge. The two most important opportunities are:

- **EV smart charging, where vehicle owners shift charging to off-peak periods:** Most electric vehicles are parked around 95% of the time,[102] offering significant flexibility in when they are charged. A typical 60 kWh EV battery stores several times more energy than a household uses in a day, even in a deeply electrified economy.[103] Smart charging enables this demand to be shifted to periods of low-cost, low-carbon electricity – such as overnight in wind-dominant, high-latitude regions, or midday in sunbelt countries with high solar potential. (See Box F, Chapter 2, for discussion of emerging midday solar surpluses in Australia).
- **Vehicle-to-grid (V2G) as a future distributed storage option:** In principle, EV batteries could also export electricity back to the grid when parked and connected for extended periods. However, V2G requires additional hardware, smart charging infrastructure, and appropriate utility protocols to ensure safe and reliable operation. These factors make the technology relatively high-cost and limited in deployment today.
- **Shifting heating and cooling loads in both residential and commercial buildings**: Space heating and cooling will be key drivers of rising electricity demand across different regions. While demand for thermal comfort is time-specific, electricity input to achieve this can be shifted by several hours if buildings are sufficiently well insulated. This opportunity is discussed in detail in the ETC's recent report, *Achieving Zero-Carbon Buildings: Electric, Efficient and Flexible.*[104] Improving insulation involves upfront investment - particularly in retrofitting existing buildings - but often delivers cost savings by reducing total energy use, even before accounting for demand-shifting benefits. It can therefore be a very low-cost method to provide short duration balancing flexibility.

Exhibit 1.27 sets out the estimated potential for DSF in the buildings and road transport sectors. In principle, up to 25% of total electricity demand in these sectors could be time-shifted with minimal impact on consumer comfort or convenience, and at low cost.

Seizing this large potential in the household and commercial sectors will require the development of time-of-day pricing. The ETC's Briefing Note, *Demand side flexibility – unleashing untapped potential for clean power*[105] discusses this and other actions required to drive DSF adoption which we also consider in Chapter 4 of this report.

As shown in Exhibit 1.28, there are also significant opportunities for short duration DSF in industrial sectors, and longer duration DSF in the production of green hydrogen.

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[97] United States Department of Energy (DOE) (2020), *Hydrogen Storage Technical Assessment: Underground Storage.*

[98] IEA (2021), *Global Hydrogen Review.*

[99] HyUnder Consortium (2013), *Assessment of Potential for Large-Scale Underground Hydrogen Storage in Europe.*

[100] Oxidation is exothermic which refers toreleasing energy and reduction is endothermic which refers torequiring energy.

[101] ETC (2025), *Demand side flexibility – unleashing untapped potential for clean power.*

[102] IEA (2020), *Global EV Outlook 2020.*

[103] NREL (2023), *Opportunities for Vehicle-Grid Integration in a Decarbonised Energy System.*

[104] ETC (2025), *Achieving Zero-Carbon Buildings: Electric, Efficient and Flexible.*

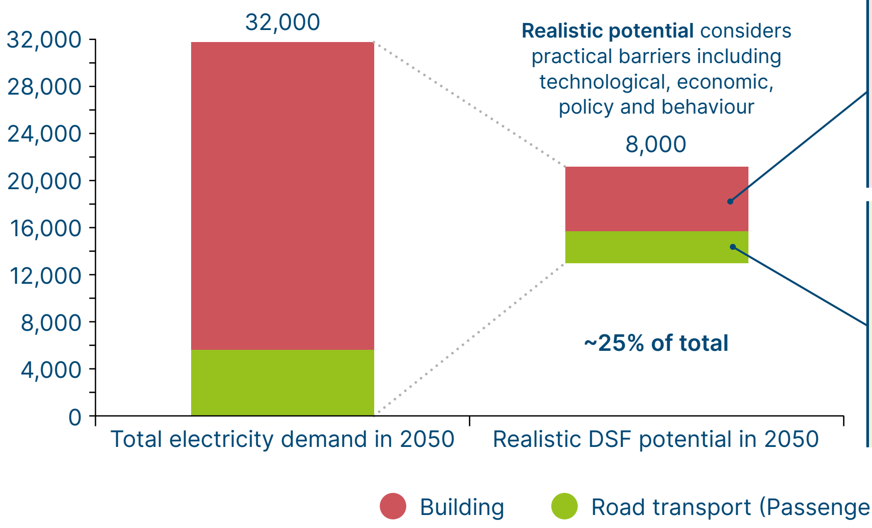
[105] ETC (2025), *Demand side flexibility – unleashing untapped potential for clean power.*

Exhibit 1.27

~25% of building and passenger EV electricity demand in 2050 could be flexible

Global electricity demand and DSF potential, 2050

TWh



Buildings

In our realistic scenario, 20% of building electricity demand could become flexible by 2050.

- Savings made by:
  - Heating and cooling flexibility, enabled by thermal energy storage and insulation.
  - Lighting and appliance flexibility, via smart technologies and management systems.

Electric Vehicles

- By 2050, ~50% of demand could be flexible with smart charging and V2G tech.
- Enabled by:
  - Smart charging solutions is a low-cost solution that enables charging at low demand or high renewable generation.
  - V2G technology enables EVs to discharge power back to grid, but has less potential as more costly, and presents concerns around battery degradation.

NOTE: In our briefing note, *Demand side flexibility – unleashing untapped potential for clean power,* we look at two scenarios "realistic" and "theoretical" to consider the ideal possibilities and what can be realistically achievable. In this analysis, we focus on the realistic potential of DSF, as it provides a more grounded and actionable view of what can be delivered given today's technological, policy, economic and behavioural constraints and therefore offers a more reliable basis for system planning.

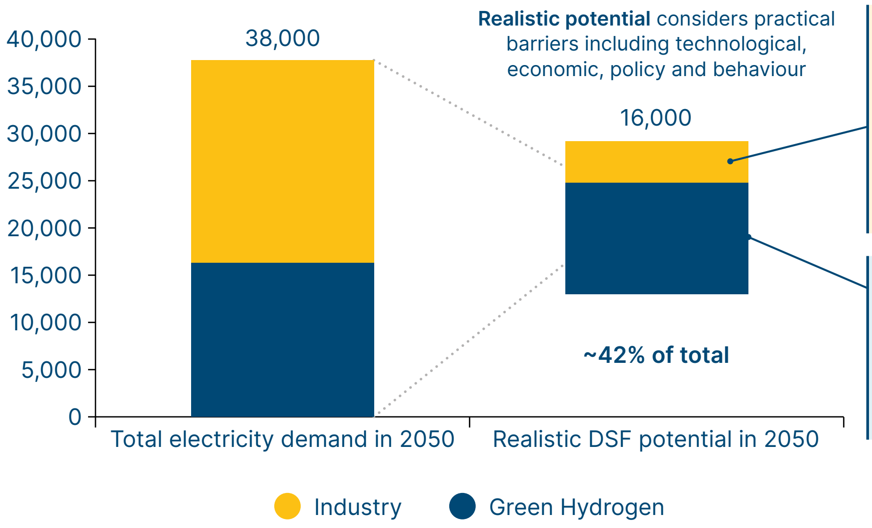
SOURCE: Systemiq analysis for the ETC; IEA (2024), *World Energy Outlook 2024;* RMI (2023), *Unlocking demand-side flexibility in China;* Macquarie (2020), *Flexibility of Hydrogen Electrolysers;* IEA (2024), *Global EV Outlook 2024;* World Electric Vehicle Journal (2019), *Flexibility of EV demand.*

Exhibit 1.28

~40% of industry and green hydrogen demand in 2050 could be flexible

Global electricity demand and DSF potential, 2050

TWh



Industry

In our realistic scenario, 20% of industrial demand could be flexible by 2050, largely driven by hydrogen production.

- Savings made by:
  - Electrified industrial heat, one key route being heat storage.
  - Batch processes being adjusted or paused.
  - Data centres that can time-shift or load-shift their energy use.

Hydrogen

- 75% of potential industrial flexibility by enabling green hydrogen production to be flexible.
- This is due to 80–90% of green hydrogen electrolysis load being flexible.
- Enabled by:
  - Ramping electrolysers up or down based on grid needs.

NOTE: In our briefing note, *Demand side flexibility – unleashing untapped potential for clean power,* we look at two scenarios "realistic" and "theoretical" to consider the ideal possibilities and what can be realistically achievable. In this analysis, we focus on the realistic potential of DSF, as it provides a more grounded and actionable view of what can be delivered given today's technological, policy, economic and behavioural constraints and therefore offers a more reliable basis for system planning.

SOURCE: Systemiq analysis for the ETC; IEA (2024), *World Energy Outlook 2024;* RMI (2023), *Unlocking demand-side flexibility in China;* Macquarie (2020), *Flexibility of Hydrogen Electrolysers;* IEA (2024), *Global EV Outlook 2024;* World Electric Vehicle Journal (2019), *Flexibility of EV demand.*

- **Heat batteries** convert electricity into heat, which can then be stored in cheap widely available materials. This heat energy can either be output later on directly or converted back into electricity. They are particularly effective when the stored energy is used directly for heat, minimising conversion losses associated with electricity-to-heat-to-electricity cycles. By converting variable renewable electricity into continuous, high-temperature thermal energy, heat batteries enable industrial processes to have constant heat supply from variable power generation. Currently, over 40 technology providers offer heat batteries or heat-as-a-service solutions to support industrial decarbonization.[106] However, the technology remains nascent due to high upfront costs, limited industry awareness, and integration challenges within existing industrial processes. Widespread adoption will depend on further cost reductions, supportive policies, and increased demonstration projects to prove their reliability at scale.[107]
- **Hydrogen production via electrolysis,** coupled with storage in salt caverns and subsequent combustion in gas turbines, is anticipated to play a role in long-duration energy balancing, especially in high latitude, wind-rich regions. Beyond grid balancing, a zero-carbon economy will necessitate substantial volumes of zero-carbon hydrogen to decarbonise sectors such as aviation, shipping, steel, fertilisers, and petrochemicals. Projections indicate that achieving a global zero-carbon economy could require the production of approximately 350–500 million tonnes of clean hydrogen annually by 2050.[108] If 80% of this were via electrolysis this would require an electricity input of 14,000-20,000 TWh per annum (assuming 50 MWh input per tonne).[109]

While some green hydrogen will likely be produced using dedicated wind and solar sources, integrating electrolysis with grid electricity can optimise costs by operating during off-peak, low-price periods. This approach leverages periodic surpluses of electricity supply inherent in highly renewable systems. Modern electrolysers are increasingly flexible, enabling DSF over short durations. A recent UK study also found that electrolysers, when strategically located in constrained grid zones, could offer highly responsive demand side flexibility while reducing transmission congestion and constraint costs.[110]

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[106] Systemiq (2024), *Catalysing the Global Opportunity for Electrothermal Energy Storage: Promising New Technologies for Building Low-Carbon, Competitive, and Resilient Energy Systems.*

[107] WBCSD (2024), *Industrial Heat: An Overlooked Piece in the Decarbonization Puzzle.*

[108] Systemiq analysis for the ETC.

[109] ETC 2021, *Making the Hydrogen Economy Possible: Accelerating Clean Hydrogen in an Electrified Economy.*

[110] Arup, National Grid ESO & National Gas Transmission (2024), *Hydrogen Production from Thermal Electricity Constraint Management.*

1.5 Relative costs of balancing options and optimal mix by duration

This section considers the relative costs of the different balancing options and the factors that will determine the optimal mix of different approaches by duration of balancing need. It covers in turn:

- Model methodology and key assumptions
- Summary estimates of relative costs
- Short duration balancing: batteries plus DSF as dominant solutions
- Medium duration: A range of cost effective solutions with the dominant ones still unclear and varying by specific circumstance
- Ultra-long duration: Dispatchable gas turbines play key role, whether burning hydrogen or methane

1.5.1 Methodology and key assumptions

The need for balancing supply and demand in wind and solar dominated systems means that total system generation costs will exceed the cost of generation alone. The nature of these additional costs depends on the specific balancing technologies or business models employed.

- For energy storage, the main cost drivers are the capital cost per kWh of storage capacity and the round-trip efficiency, the percentage of input electricity that can be recovered for end use. Exhibit 1.29 presents projected capital costs and efficiencies for selected storage technologies in 2035. Additionally, for storage systems with round-trip losses, the cost per usable kWh depends on the price of input electricity: The higher the input cost, the greater the impact of those efficiency losses. Box E illustrates how the LCOE, storage capital costs, and round-trip efficiency together influence the LCOS.
- Demand side flexibility costs are more difficult to quantify and are often low or zero. For example, if an EV driver shifts charging to off-peak hours to benefit from lower prices, the cost may be negligible beyond any inconvenience of behavioural adjustment. However, some forms of DSF — such as improved insulation to allow shifting of heating or cooling — do involve capital costs, as discussed in the ETC's report on *Achieving Zero-Carbon Buildings*.[111] However these investments may be justified independently by reductions in overall household energy use.
- Running fossil fuel plants flexibly (rather than at baseload) has cost implications due to reduced utilisation. The cost impact depends on the specific plant type (e.g., OCGT vs. CCGT), as well as whether the plant is already built or new - with new builds incurring full capital recovery requirements.
- The cost of long-distance transmission is primarily driven by the capital and operational cost of transmission lines and end-point infrastructure. However, in some cases these costs may be fully or partially justified by generation cost arbitrage (i.e. connecting regions with different LCOEs). In such cases, the balancing benefits of interconnection may be realised at little or no incremental cost.

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[111] ETC (2025), *Achieving Zero-Carbon Buildings: Electric, Efficient and Flexible.*

Exhibit 1.29

Assumptions incorporated into 2035 LCOE and LCOS cost models

$/MWh

	Efficiencies, %	Discount Rate, %	Lifetime, years	Capacity factor, %
Demand side flexbility	Range taken	Range taken	Range taken	
Lithium-ion and Sodium-ion[A]	**LIB** 95 **SIB** 93			
Energy Storage[A]	**LIB** 92–95% **SIB** 90–93% **Flow Battery** 88–90% **CAES** 70% **Thermal storage** 80% **Pumped hydro** 80%	**LIB, SIB, Flow, CAES, Thermal** 7–10% **Pumped hydro** 16–27%	250 cycles per year for 10 hour duration 70 cycles per year for 20 hours duration	
Long-distance transmission	Transmission losses of 3% per 1000 km incorporated	MWhs discounted at a rate of 3.5% per annum starting from the first year of generation	50 years cable life	85 (utilisation rate of cable)
Nuclear and Hydropower	N/A	**Nuclear** 4.5–8.5% **Hydro** 5%	**Nuclear** 40 **Hydro** 50	45
H_2 in OCGT[A], CCS on CCGT, Unabated gas	**OCGT efficiency –** 40% **CCGT efficiency –** 50% **CCS efficiency penalty –** 7 percentage points	**H_2 OCGT** 8 **CCGT and CCS, Unabated gas** 7	30 across all	Set at 5% to reflect ultra-long duration, apart from CCS on CCGT which is set to 10%.

NOTE: (A) Electricity input costs are included in the cost estimates for storage technologies (e.g., batteries, CAES, thermal) and ultra-long balancing tech (e.g., hydrogen in OCGTs), because these technologies do not generate electricity themselves — they require input electricity to deliver output. By contrast, DSF, long-distance transmission, nuclear, hydropower and CCGTs are treated as net generators or enablers of generation and thus do not have electricity input costs applied. Fuel costs are accounted for in the variable OPEX (specified in $/kWh) for all gas-fired OCGT and CCGT technologies, with an assumed natural gas cost of $6/MMBtu and hydrogen costs derived using the methodology outlined in Section 1.4.5 of this report. DSF = demand side flexibility, LIB = lithium-ion battery, SIB = sodium-ion battery, OCGT = open cycle gas turbine, CCGT = combined cycle gas turbine, CCS = carbon capture and storage.

SOURCE: Systemiq analysis for the ETC; BNEF (2024), *Long duration energy storage cost survey;* BNEF (2025), *LCOE Data Viewer Tool;* PNNL (2025), *Pumped Hydro Energy Storage;* BNEF (2024), *GridVal 1.0;* BNEF (2024), Electrolysis System Cost Forecast 2050: Higher for Longer. D. Mullen (2024), *On the cost of zero carbon electricity: A techno-economic analysis of combined cycle gas turbines with post-combustion CO_2 capture.*

Box E

Levelised cost of electricity (LCOE) and levelised cost of storage (LCOS) methodology

Overview: Our estimates of the cost of different storage/flexibility options are set out in Exhibits 1.32, 1.33 and 1.34, where the figures shown are the costs of delivered electricity in 2035 given different assumptions for the input price of electricity. We have chosen 2035 as the reference year for this cost modelling to reflect the urgency of investment decisions that must be made within the next decade to ensure adequate deployment of storage solutions in time to support power system decarbonisation. In Section 1.6 we present estimates of total generation cost for systems built in 2050: this helps identify the long-term cost of systems with high levels of wind and solar compared with those which would result if we continued to rely primarily on fossil fuels.

We present LCOE values for generation technologies and LCOS values for storage technologies, based on the following techno-economic inputs:

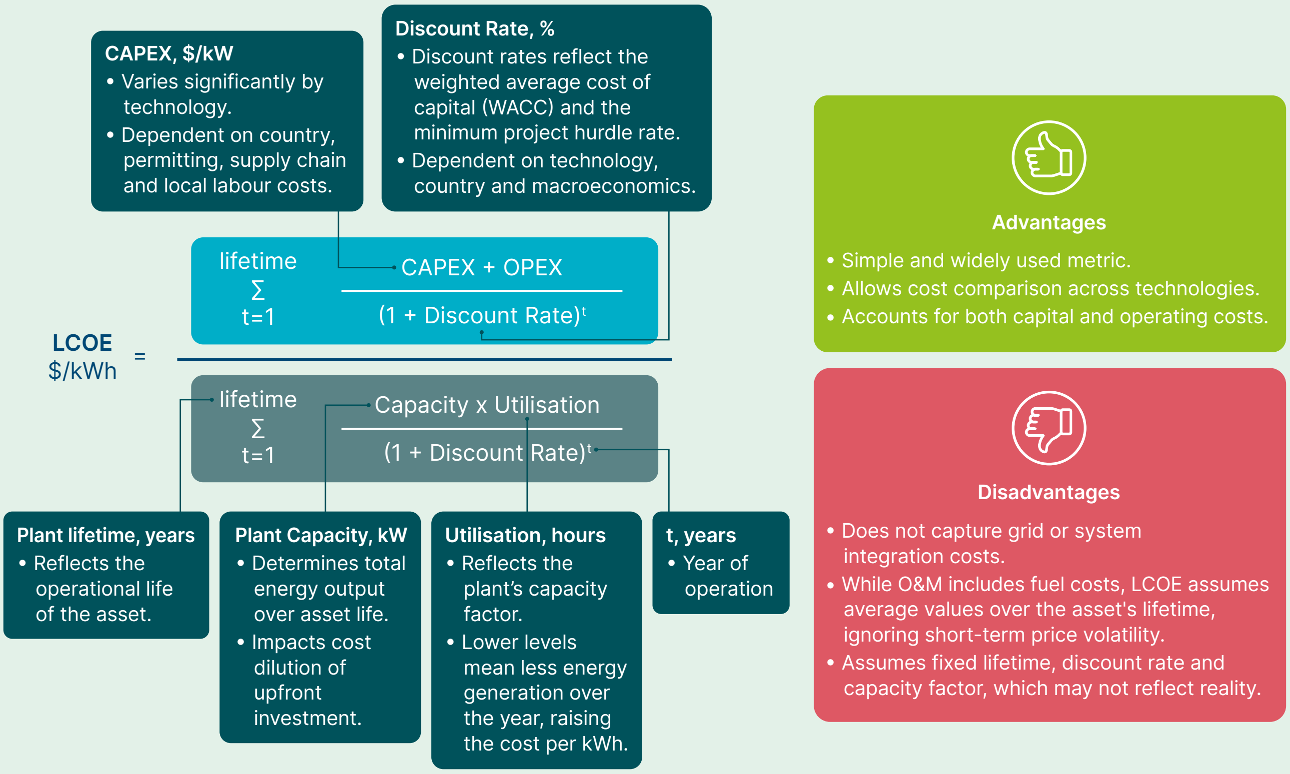
- The LCOE formula is used to calculate costs for long-distance transmission, nuclear, hydropower, CCS on CCGT, and unabated gas, modelled on OCGT gas turbines. These generation technologies directly produce electricity with no electricity input, making LCOE the appropriate metric to assess their cost per unit of energy output over their lifetime.
- LCOS has been used in relation to all energy storage categories, including batteries, thermal storage, pumped hydropower, compressed air and hydrogen storage costs. These technologies store previously generated electricity and later discharge it, meaning their costs are best evaluated based on the energy they can deliver over time, accounting for efficiency losses, cycling rates, and charging costs.

While LCOE and LCOS measure different cost combinations, they can be used to compare the relative costs of different balancing technologies, and to highlight the trade-offs between flexible generation and storage solutions in meeting system needs.

The methodology and assumptions entailed in their estimation are shown in Exhibits 1.30 and 1.31.

Exhibit 1.30

LCOE calculation overview



CAPEX, $/kW
- Varies significantly by technology.
- Dependent on country, permitting, supply chain and local labour costs.

Discount Rate, %
- Discount rates reflect the weighted average cost of capital (WACC) and the minimum project hurdle rate.
- Dependent on technology, country and macroeconomics.

$$\text{LCOE \$/kWh} = \frac{\sum_{t=1}^{\text{lifetime}} \frac{\text{CAPEX + OPEX}}{(1 + \text{Discount Rate})^t}}{\sum_{t=1}^{\text{lifetime}} \frac{\text{Capacity x Utilisation}}{(1 + \text{Discount Rate})^t}}$$

Plant lifetime, years
- Reflects the operational life of the asset.

Plant Capacity, kW
- Determines total energy output over asset life.
- Impacts cost dilution of upfront investment.

Utilisation, hours
- Reflects the plant's capacity factor.
- Lower levels mean less energy generation over the year, raising the cost per kWh.

t, years
- Year of operation

Advantages
- Simple and widely used metric.
- Allows cost comparison across technologies.
- Accounts for both capital and operating costs.

Disadvantages
- Does not capture grid or system integration costs.
- While O&M includes fuel costs, LCOE assumes average values over the asset's lifetime, ignoring short-term price volatility.
- Assumes fixed lifetime, discount rate and capacity factor, which may not reflect reality.

NOTE: LCOE calculates the average cost of constructing and operating a power generation asset over its entire lifespan, divided by the total electricity it produces.

SOURCE: Systemiq analysis for the ETC.

Assumptions: LCOE

- LCOE calculations include figures for Plant Capacity, CAPEX, OPEX, Capacity Factor, Discount Rate based on data from BNEF and Systemiq analysis for the ETC.
- Capacity factor for long duration assets was set at 5% to reflect the low utilisation of ultra-long duration storage.
- Two scenarios were run, one based on technologies based in China and the other ex-China to compare the cost variations across regions.
- For gas turbines, we assume a gas price of $8 per MMBtu.

Exhibit 1.34

LCOS calculation overview

CAPEX, $/kWh (storage capacity)
- Fixed upfront cost of storage system construction, equipment, and installation.

Electricity Cost, $/kWh
- Cost of purchasing electricity for charging. Varies with market prices.

$$\text{LCOS } \$/\text{kWh} = \frac{\sum_{t=1}^{\text{lifetime}} \frac{\text{CAPEX + OPEX + Charging Rate}}{(1 + \text{Discount Rate})^t}}{\sum_{t=1}^{\text{lifetime}} \frac{\text{Energy Discharged}}{(1 + \text{Discount Rate})^t}}$$

Round Trip Efficiency, %
- Represents energy lost in charging and discharging.
- Higher efficiency lowers LCOS.

Cycles per annum, unit
- Number of charge-discharge cycles per year.
- More cycles reduce LCOS.

Advantages
- Standardised metric for comparing storage technologies.
- Captures CAPEX, OPEX, efficiency losses, and cycling rates.
- Helps assess economic viability under different use cases.

Disadvantages
- Highly sensitive to efficiency, cycling rates, and electricity prices.
- Ignores market dynamics and revenue potential.
- Can be misleading when comparing different storage types.

NOTE: LCOS measures the average cost of building and operating an energy storage system over its lifetime, divided by the total energy it delivers.

SOURCE: Systemiq analysis for the ETC.

Assumptions: LCOS

- For energy storage, the key cost metric is the LCOS, which reflects the full cost of delivering usable electricity from storage. LCOS calculations incorporate CAPEX, OPEX, a discount rate, number of charge/discharge cycles per year, lifecycle efficiency, and the cost of electricity input.
- Efficiency losses are not treated as a separate cost line but are reflected implicitly through the lifecycle efficiency and electricity input cost: the lower the round-trip efficiency and the higher the input electricity price, the greater the impact on LCOS. Exhibits 1.43 and 1.44 in Section 1.5.5 illustrate how variations in efficiency and input electricity cost interact to affect overall storage economics in the ultra-long duration case.
- For energy storage and batteries, we use CAPEX based on BNEF historical and forecasted fully installed energy storage systems for short and long duration storage.[112] Fully installed system prices include battery CAPEX, power conversion equipment (PCS), balance of plant, and installation and labour, engineering, procurement and construction (EPC) and grid connection costs.
- For pumped hydropower, historical data and forecasts from PNNL were used.[113]
- H_2 storage figures are based on three models; hydrogen production ($ per kg), hydrogen storage ($ per kg), and electricity generation from H_2 powered CCGTs ($ per MWh), with data from multiple sources.[114]
- Two scenarios were run, one based on assets located in China and the other ex-China to show the impact of China's much lower current and projected costs.
- Short duration systems were modelled on a 4-hour system; medium-long duration systems were modelled on a 10-hour system.
- Estimating and comparing the relative costs of different flexibility technologies and business models requires multiple assumptions and subjective judgements, and these costs will evolve over time as technologies mature and deployment scales.

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[112] BNEF (2024), Energy Storage System Cost Survey; (2024) Long duration energy storage cost survey.

[113] PNNL (2025), *Pumped Storage Hydropower*.

[114] Systemiq analysis for the ETC: IRENA (2021), *Green Hydrogen Cost Reduction Report*; BNEF (2025), *LCOE Data Viewer*; Liu et al (2024), *Development status and prospect of salt cavern energy storage technology*.

1.5.2 Summary estimates of costs for different technologies and durations

Exhibits 1.32, 1.33 and 1.34 present indicative ranges for the cost of delivered electricity from various/storage flexibility solutions, using three illustrative assumptions for electricity input cost:

- **The first scenario assumes a zero cost of electricity input.** This reflects conditions likely to occur during certain hours of the year in high wind and solar systems, when wholesale electricity prices fall to zero due to surplus generation. Under this assumption, the cost per MWh delivered equals the levelised cost of building and operating the relevant asset, with no cost of energy losses due to round trip inefficiency .
- **This second scenario assumes an electricity input cost of $40 per MWh,** reflecting the potential cost of firmed clean power in regions with excellent renewable resources and low-cost storage. This cost should be achievable by 2035 in several markets that have made early investments into their renewable fleet, particularly in the solar-belt countries. The total costs here include the cost impact of round trip efficiency losses.
- **The third scenario assumes an electricity input cost of $70 per MWh**. The cost impact of round trip efficiency losses rises as the input electricity price increases.

In each case, the figures represent the effective cost of usable electricity delivered from the storage or flexibility solution. These should be interpreted as indicative of the relative performance and competitiveness of different technologies under varying system conditions.

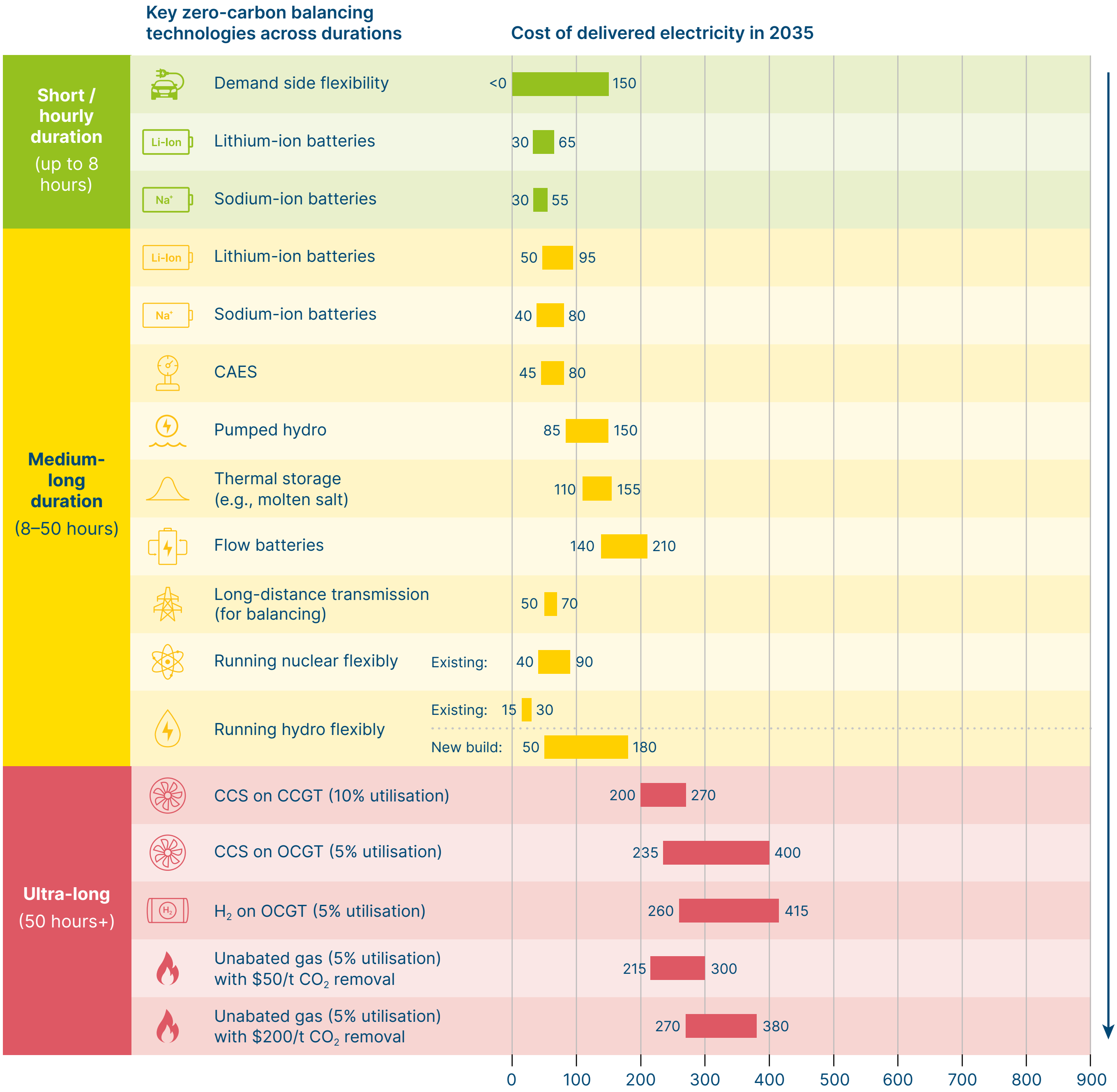
The impact of flexibility costs on total system generation costs can then be approximated by multiplying the share of total electricity shifted (i.e. not consumed at time of generation) by the LCOS. For example, if the base generation cost is $50 per MWh, the LCOS is $150 per MWh, and 10% of electricity needs to be time-shifted, the average system cost rises to:

$$(90\% \times \$50) + (10\% \times \$150) = \$60 \text{ per MWh}$$

This simplified model illustrates how even relatively high flexibility costs may have a limited effect on total system cost if only a modest share of demand must be shifted.

Exhibit 1.32

Cost comparison of balancing technologies – Electricity cost of $0/MWh (applies only to selected technologies)

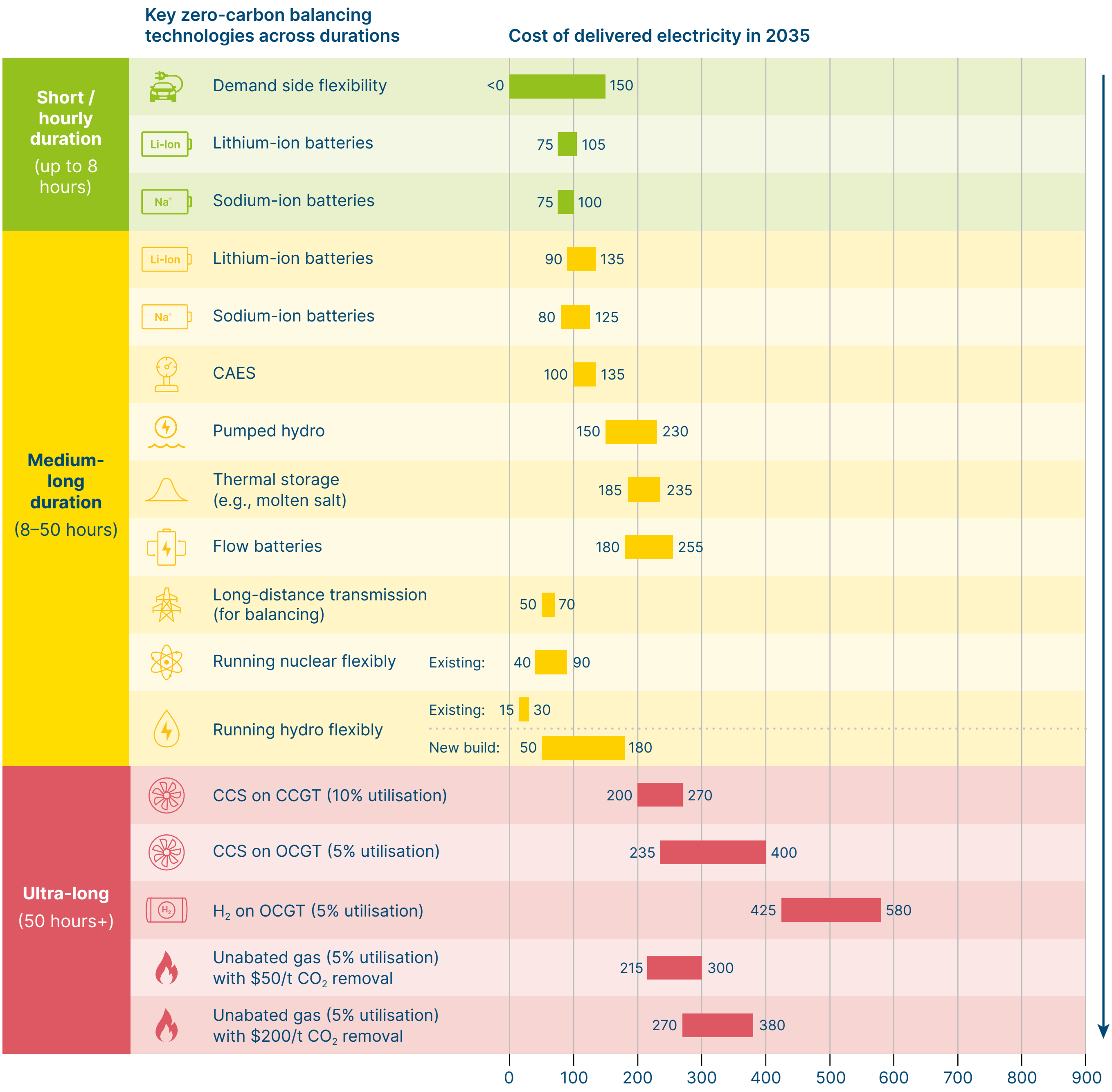


NOTE: The following assumptions are used for the following technologies: Hydrogen based on a 5% utilisation factor for OCGTs and a 50% electrolyser utilisation rate. Interconnectors assume no electricity cost input.

SOURCE: Systemiq analysis for the ETC: BNEF (2024), *Energy Storage System Cost Survey;* BNEF (2024), *Long duration energy storage cost survey;* PNNL (2025), *Pumped Hydro Energy Storage;* BNEF (2024), *Electrolysis System Cost Forecast 2050: Higher for Longer;* BNEF (2025), *LCOE Data Viewer;* Liu et al. (2021), *Development status and prospect of salt cavern energy storage technology.* D. Mullen (2024), *On the cost of zero carbon electricity: A techno-economic analysis of combined cycle gas turbines with post-combustion CO_2 capture.*

Exhibit 1.33

Cost comparison of balancing technologies – Electricity cost of $40/MWh (applies only to selected technologies)

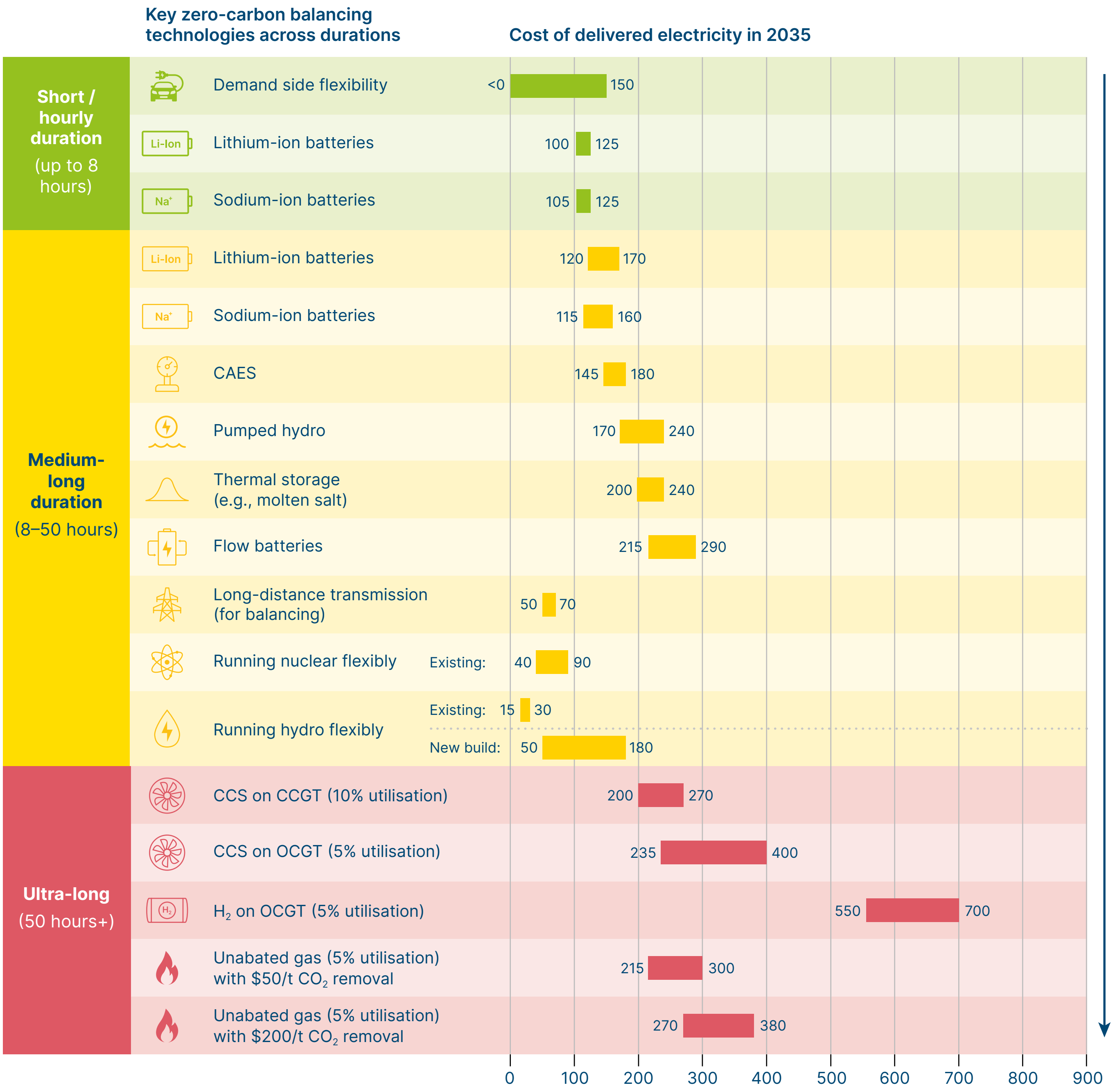


NOTE: The following assumptions are used for the following technologies: Hydrogen based on a 5% utilisation factor for OCGTs and a 50% electrolyser utilisation rate. Interconnectors assume no electricity cost input.

SOURCE: Systemiq analysis for the ETC: BNEF (2024), *Energy Storage System Cost Survey;* BNEF (2024), *Long duration energy storage cost survey;* PNNL (2025), *Pumped Hydro Energy Storage;* BNEF (2024), *Electrolysis System Cost Forecast 2050: Higher for Longer;* BNEF (2025), *LCOE Data Viewer;* Liu et al. (2021), *Development status and prospect of salt cavern energy storage technology.* D. Mullen (2024), *On the cost of zero carbon electricity: A techno-economic analysis of combined cycle gas turbines with post-combustion CO_2 capture.*

Exhibit 1.34

Cost comparison of balancing technologies – Electricity cost of $70/MWh (applies only to selected technologies)



NOTE: The following assumptions are used for the following technologies: Hydrogen based on a 5% utilisation factor for OCGTs and a 50% electrolyser utilisation rate. Interconnectors assume no electricity cost input.

SOURCE: Systemiq analysis for the ETC: BNEF (2024), *Energy Storage System Cost Survey;* BNEF (2024), *Long duration energy storage cost survey;* PNNL (2025), *Pumped Hydro Energy Storage;* BNEF (2024), *Electrolysis System Cost Forecast 2050: Higher for Longer;* BNEF (2025), *LCOE Data Viewer;* Liu et al. (2021), *Development status and prospect of salt cavern energy storage technology.* D. Mullen (2024), *On the cost of zero carbon electricity: A techno-economic analysis of combined cycle gas turbines with post-combustion CO_2 capture.*

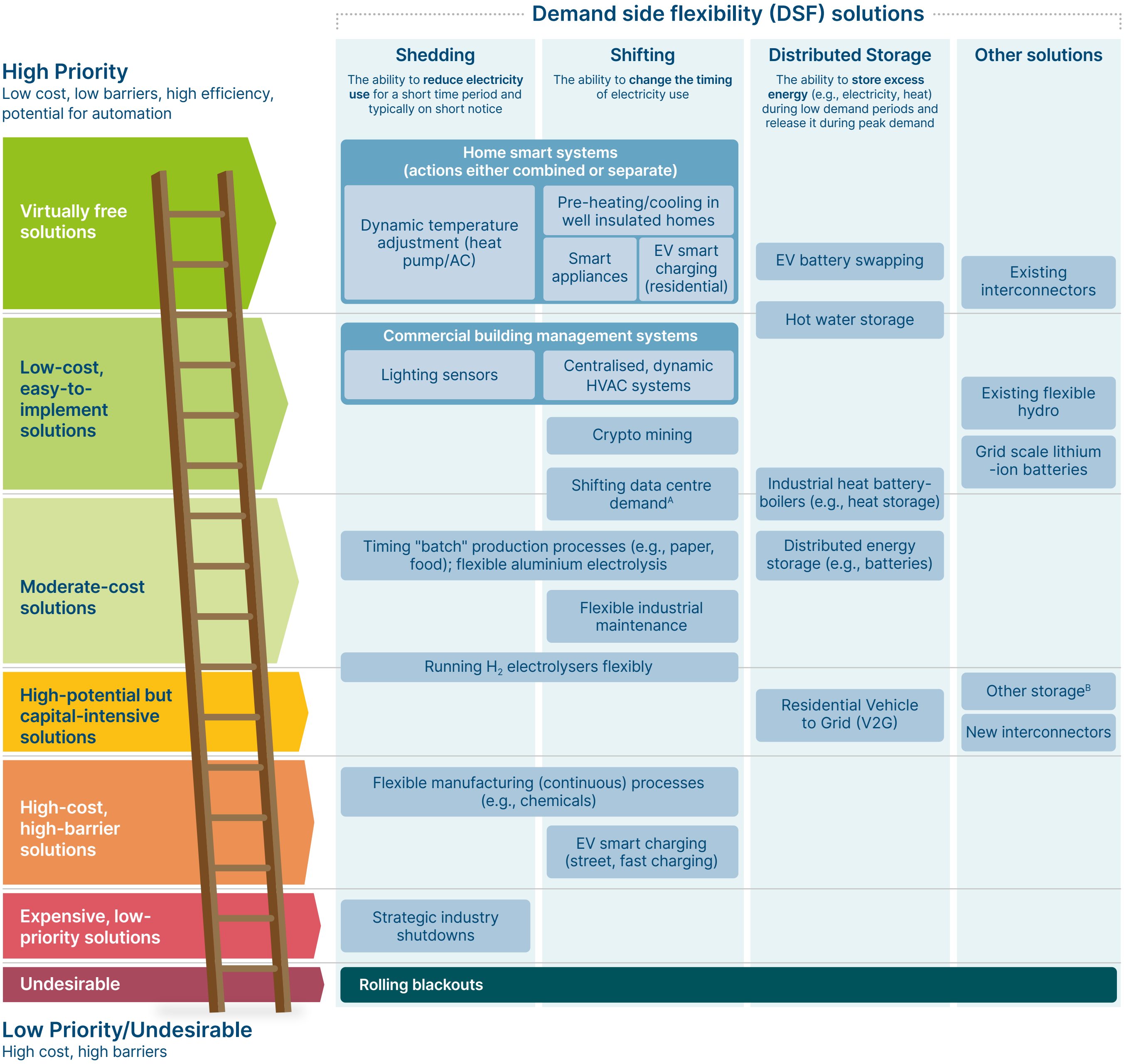
1.5.3 Short duration: Batteries and demand side flexibility are the dominant solutions

In most regions demand side flexibility and battery storage technologies - particularly lithium-ion and sodium-ion - will enable short-term balancing at relatively low cost.

As discussed above, many demand side flexibility options - such as shifting EV charging or pre-heating buildings - are effectively costless to deploy, as they rely on existing equipment and involve minimal behavioural disruption. This is seen in our DSF Ladder, noted below in Exhibit 1.35, adapted from Michael Liebreich's Hydrogen Ladder.

Exhibit 1.35

Short-duration Flexibility Ladder



	Demand side flexibility (DSF) solutions			
High Priority Low cost, low barriers, high efficiency, potential for automation	**Shedding** The ability to **reduce electricity use** for a short time period and typically on short notice	**Shifting** The ability to **change the timing** of electricity use	**Distributed Storage** The ability to **store excess energy** (e.g., electricity, heat) during low demand periods and release it during peak demand	**Other solutions**
Virtually free solutions	**Home smart systems (actions either combined or separate)** Dynamic temperature adjustment (heat pump/AC)	Pre-heating/cooling in well insulated homes Smart appliances EV smart charging (residential)	EV battery swapping Hot water storage	Existing interconnectors
Low-cost, easy-to-implement solutions	**Commercial building management systems** Lighting sensors	Centralised, dynamic HVAC systems Crypto mining Shifting data centre demand[A]	Industrial heat battery-boilers (e.g., heat storage)	Existing flexible hydro Grid scale lithium-ion batteries
Moderate-cost solutions	Timing "batch" production processes (e.g., paper, food); flexible aluminium electrolysis Running H_2 electrolysers flexibly	Flexible industrial maintenance	Distributed energy storage (e.g., batteries)	
High-potential but capital-intensive solutions			Residential Vehicle to Grid (V2G)	Other storage[B] New interconnectors
High-cost, high-barrier solutions	Flexible manufacturing (continuous) processes (e.g., chemicals)	EV smart charging (street, fast charging)		
Expensive, low-priority solutions	Strategic industry shutdowns			
Undesirable	Rolling blackouts			
Low Priority/Undesirable High cost, high barriers				

NOTE: A) Non-critical data processes, such as AI training, can be **postponed or shifted** to low-demand periods without real-time constraints. Flexibility also exists when companies run computing centres across different countries / regions to allow **load shifts over geographies.** B) Medium-duration storage (including pumped hydro) **is less competitive for short-duration balancing** than batteries, driven by the higher round-trip efficiency of batteries.

SOURCE: This DSF ladder infographic is published under CC-BY 4.0 and the ladder concept has been adapted from Michael Liebreich/Liebreich Associates, Clean Hydrogen Ladder, Version 5.0, 2023. Original Concept credit: Adrian Hiel, Energy Cities.

Other routes, such as those requiring insulation or smart controls, entail modest capital costs but are still low-cost relative to alternative flexibility options. Maximising the potential for DSF is therefore a critical priority in building low-cost, high-renewable power systems.

Based on the assumptions in Exhibit 1.35, lithium-ion batteries could deliver stored electricity at a total cost of \$30–65 per MWh when electricity input is assumed to be zero-cost (as may occur during periods of wind and solar surplus). When an electricity input cost of \$70 per MWh is assumed, the LCOS rises to \$100–125 per MWh. These results show that even when input electricity is valued at \$70 per MWh, both demand side flexibility and battery-based solutions (particularly sodium-ion) remain competitive. The relatively high efficiency of lithium-ion and sodium-ion batteries (typically 85–90%) helps contain LCOS even when electricity input is not free.

Sodium-ion batteries, while less commercially mature today, are expected to undercut lithium-ion in cost by 2035.[115] This is due to their use of more abundant and lower-cost materials (such as sodium instead of lithium and cobalt), their improved thermal stability which reduces safety-related system costs, and potentially lower degradation rates under specific operating conditions. However, these projections depend on successful large-scale commercialisation and further performance optimisation.

Scaling these cost-effective short duration balancing solutions will require supportive policy and market frameworks. For battery storage, key enablers include access to multiple revenue streams – energy, capacity, and ancillary services markets – and expedited grid connection processes. For DSF, persistent barriers such as low consumer awareness, regulatory uncertainty, limited financial incentives, and infrastructural constraints (e.g., smart meter availability) continue to limit uptake.[116] Additionally, data privacy and cybersecurity concerns remain important deterrents to consumer engagement. Solutions to overcome these challenges are explored further in Chapter 4.

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[115] NE Research (2024), *Revolutionizing Energy: China's Sodium-Ion Batteries Set to Outpace Lithium by 2025, Sparking a \$14 Billion Market Transformation.*

[116] ETC (2024), *Demand side flexibility: unleashing untapped potential alongside electricity grids and storage.*

1.5.4 Medium-long duration: Optimal solutions will vary by specific circumstances

The cost of medium-long duration balancing options will vary significantly by country with some able to utilise low-cost options made possible by existing assets, resources or location. Costs can be minimised if countries:

- Have significant existing hydropower generation or hydro resources to support low-cost hydropower development.
- Have existing nuclear assets which can vary output in line with medium term variations in demand or wind and solar supply.
- Are well located to develop long-distance (including international) transmission to regions which have lower wind and solar generating costs and uncorrelated weather systems.

As research into long-duration energy storage costs from BNEF highlights,[117] in countries with such advantages, some medium- to long-duration balancing options – e.g., long-distance transmission, flexible operation of existing nuclear and hydro assets - can be delivered at lower cost per MWh than short-duration lithium-ion battery storage.

In contrast, when such conditions do not apply, medium- to long-duration balancing is likely to be significantly more expensive. This is due to:

- The relatively higher cost per cycle of lithium-ion batteries, which are optimised for frequent cycling and become less cost-effective at low cycle rates.
- The lower round-trip efficiencies of alternatives such as CAES and pumped hydropower, which lead to higher costs when electricity input prices are not negligible.

The relative cost-competitiveness of different technologies shifts in favour of non-lithium-ion alternatives as storage duration increases. Lithium-ion battery capital costs are dominated by energy-related costs (per kWh), which are largely invariant with duration of use since they scale with energy capacity ($ per kWh), but their cost per kWh delivered increases when used infrequently. In contrast, technologies like CAES and flow batteries (e.g., vanadium redox flow) involve both fixed capacity costs ($ per kW) and scalable energy storage costs ($ per kWh), meaning their average cost per kWh delivered falls as duration increases.[118,119]

This is highlighted by BNEF’s Long Duration Energy Storage Cost Survey, which showcases that:[120]

- At durations below 10 hours, lithium-ion batteries remain cost-competitive.
- CAES becomes a lower-cost option at durations between 10 and 20 hours, due to its more favourable scaling characteristics.
- Pumped hydropower is increasingly favourable at durations above 20 hours due to its low marginal operating costs, long asset lifetimes, and high round-trip efficiency over extended storage durations.
- Flow batteries, while potentially suited to longer durations, are currently less competitive due to high raw material costs (e.g., vanadium) and limited economies of scale. Their competitiveness depends heavily on whether they reach large-scale commercialisation before other technologies fill the market need.

Exhibit 1.36 and Exhibit 1.37 illustrate projected LCOS ranges for medium-long duration storage modelled at 10- and 20-hour duration in 2035, across technologies and geographies. Lithium-ion and sodium-ion batteries remain the lowest-cost options at 10-hour durations in China (around $100–105 per MWh), but their cost increases significantly at 20 hours, reaching $330–380 per MWh ex-China.

By contrast, CAES and pumped hydro become increasingly competitive as duration increases. While both are more expensive than lithium-ion at 10 hours, by the 20-hour mark, CAES and pumped hydro cost is 30–40% lower than lithium-ion and 25–35% lower than sodium-ion in both China and ex-China cases. This reflects three key advantages:

- Low marginal cost of added storage: Both CAES and pumped hydro can add storage capacity at relatively low cost, via additional cavern volume or larger reservoirs, without a proportionate increase in total system cost.
- Decoupled power and energy scaling: These technologies allow independent sizing of power (e.g., turbines, pumps) and energy capacity (e.g., water volume, air pressure), making them more cost-efficient for long-duration applications than battery systems.

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[117] BNEF (2024), *Lithium-Ion Batteries are set to Face Competition from Novel Tech for Long-Duration Storage: BloombergNEF Research)*

[118] Since Power = Energy / Duration, increasing duration (e.g., from 4 h to 12 h) means you need less power per unit of energy, but only if the technology allows energy to scale independently of power.

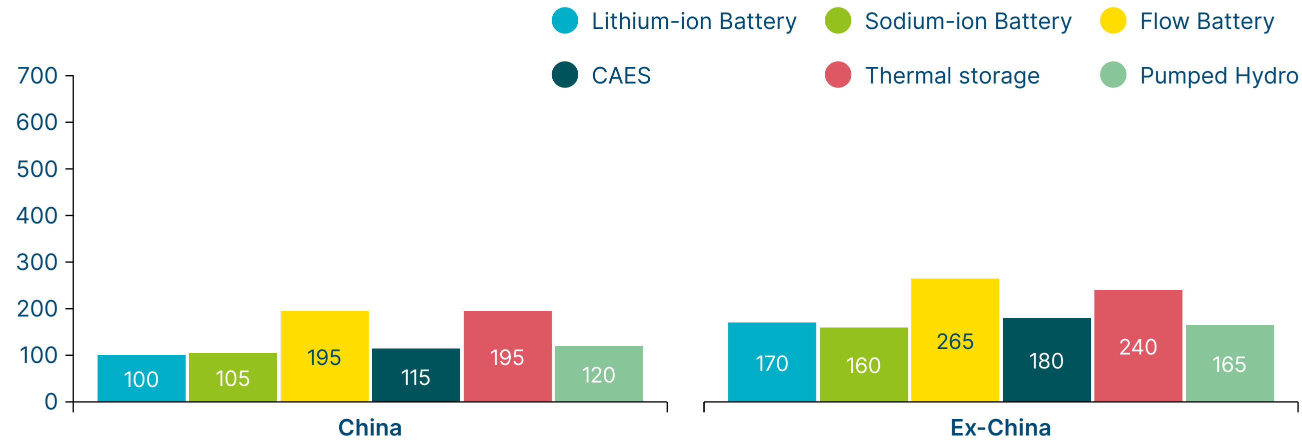
[119] BNEF (2024), *2024 Long duration energy storage cost survey.*

[120] BNEF (2024), 2024 *Long duration energy storage cost survey.*

Exhibit 1.36

Medium-long duration balancing costs at 10-hour duration

LCOS costs for medium-duration storage (including input electricity price), 2035, at 10-hour duration
$/MWh



Efficiency	95%	93%	93%	70%	80%	80%	95%	93%	93%	70%	80%	80%
	Electricity price - $0.05/kWh						**Electricity price - $0.07/kWh**					

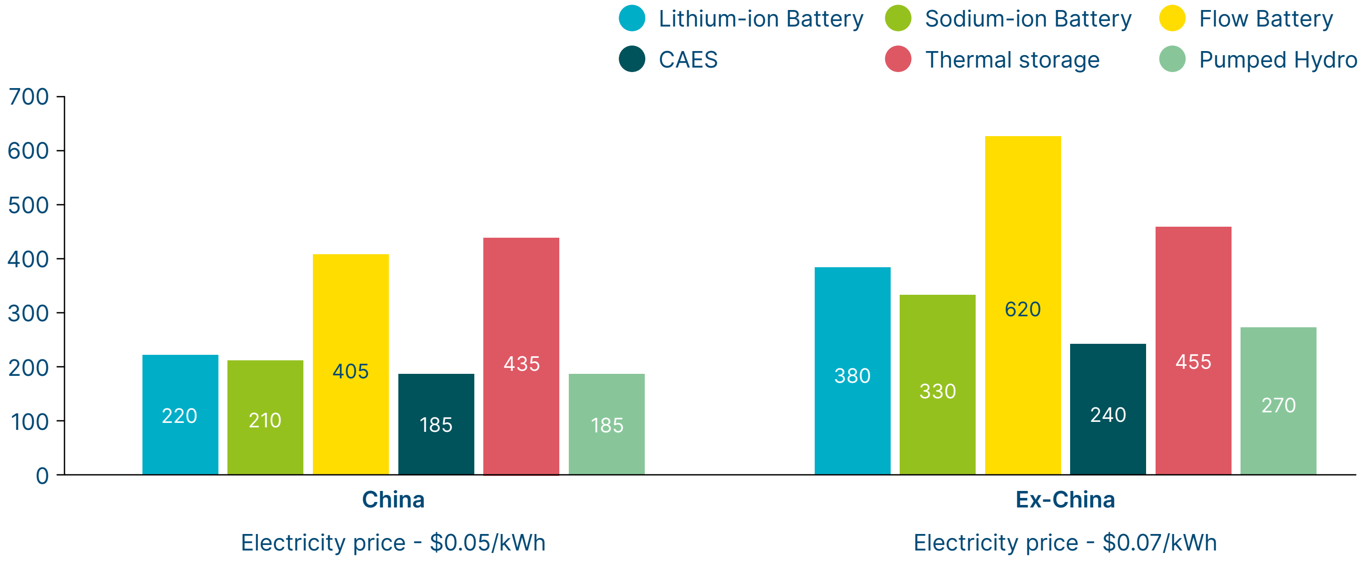
NOTE: The levelised cost of storage (LCOS) calculations incorporate several key assumptions. CAPEX figures reflect fully installed energy storage system prices from BNEF, including battery CAPEX, PCS, balance of plant, and installation and labour, engineering, procurement, and construction (EPC) as well as grid connection costs. A model has then used the 2024 figures to apply a depreciating forecast to attain values for 2035, as seen in this graph. The electricity price is assumed to be $0.05/kWh in China and $0.07/kWh in ex-China in 2035. Lifecycle efficiency varies by technology.

SOURCE: BNEF (2024), *Energy Storage System Cost Survey;* BNEF (2024), *Long duration energy storage cost survey;* Pacific Northwest National Laboratory (2025), *Pumped Hydro Energy Storage.*

Exhibit 1.37

Medium-long duration balancing costs at 20-hour duration

LCOS costs for long-duration storage (including input electricity price), 2035, at 20-hour duration
$/MWh



Efficiency	92%	90%	88%	70%	80%	80%

Efficiency	92%	90%	88%	70%	80%	80%

NOTE: The levelised cost of storage (LCOS) calculations incorporate several key assumptions. Capital expenditure CAPEX figures reflect fully installed energy storage system prices from BNEF, including battery CAPEX, PCS, balance of plant, and installation and labour, EPC as well as grid connection costs. A model has then used the 2024 figures to apply a depreciating forecast to attain values for 2035, as seen in this graph. The electricity price is assumed to be $0.05/kWh in China and $0.07/kWh in ex-China. Lifecycle efficiency varies by technology.

SOURCE: BNEF (2024), *Energy Storage System Cost Survey*; BNEF (2024), *Long duration energy storage cost survey*; PNNL (2025), *Pumped Hydro Energy Storage*.

- Minimal degradation and long asset lifetime: Unlike electrochemical storage, CAES and pumped hydro rely on mechanical processes that experience minimal degradation, enabling longer lifespans and lower lifetime costs, especially in systems with infrequent cycling.

Meanwhile, our analysis suggests that on average flow batteries will have slightly higher LCOS across all durations, particularly ex-China: this reflects higher capital costs and the comparatively earlier stage of technology development of compared to incumbents such as lithium-ion and pumped hydro.

Thermal storage, or molten salt, appears broadly uncompetitive in China and ex-China at both durations, primarily due to its higher system integration and infrastructure requirements. Unlike battery or compressed air systems and pumped hydro, molten salt storage requires high-temperature environments, complex heat exchange systems, and integration with compatible generation assets (such as concentrated solar power (CSP) or steam turbines), all of which drive up capital costs.[121] Additionally, limited deployment to date means costs have not benefitted from the same learning curve or economies of scale as battery technologies, further reducing its competitiveness on a levelised cost basis.[122]

Together, these results highlight CAES and pumped hydro as cost-effective solution for long-duration storage, especially in systems with low cycling needs and deep balancing requirements — outperforming battery technologies in cost at durations beyond 10 hours. Costs for both technologies are now beginning to fall, driven by engineering and system-level innovation. In China, recent CAES projects have achieved higher round-trip efficiencies and modular construction approaches that reduce installation costs and timelines.[123,124] In India, pumped hydro is benefitting from streamlined permitting, standardised procurement models, and competitive fixed-cost contracts, such as JSW's 2025 project with low annual capacity charges and multi-hour flexibility, bringing total project costs down compared to earlier developments.[125] These trends suggest that long-duration storage costs are likely to decline significantly over the coming years, enhancing their role in power system flexibility.

[121] RPOW, *Molten Salt Energy Storage*. Available at https://rpow.es/energy-storage-solutions/molten-salt-energy-storage/. [Accessed March 2025].

[122] Thunder Said Energy, *Costs of Thermal Energy Storage*. Available at https://thundersaidenergy.com/downloads/thermal-energy-storage-cost-model/. [Accessed March 2025].

[123] China Energy Engineering Corp (2025), World's Largest Compressed Air Energy Storage Facility Comes Online in Hubei

[124] Harbin Electric Corporation & CAS Institute of Rock and Soil Mechanics (2024), Phase II Jintan A-CAES Breaks Ground in Jiangsu

[125] JSW (2025), JSW to Develop 5.1 GW Pumped Hydro in Sonbhadra

1.5.5 Ultra-long duration: There is significant uncertainty around the long-term choice between hydrogen and natural gas as fuels for dispatchable gas turbines

Ultra-long duration storage (50+ hours) is crucial for ensuring electricity supply during prolonged periods of low renewable generation, such as extended low-wind conditions. As discussed in Section 1.4 of this chapter, the need for such storage is minimal in many sun belt countries. Even in high latitude, wind belt countries, the number of hours requiring ultra-long storage can be limited, potentially under 5% of the year (<500 hours), in systems designed with deliberately oversized wind and solar capacity, [Exhibit 1.13]. Shifting these hours will be expensive since it involves the use of assets cycled only a small number of times per year.

To illustrate the cost implications of this challenge, we have modelled the delivered electricity cost of technologies capable of providing ultra-long duration flexibility. We have chosen 2050 as the reference year, as this challenge is likely to emerge during the "last mile" of decarbonisation, where alternative sources of system balancing are more limited and infrequent events have a proportionally larger impact on system adequacy.

In countries with significant hydro resources, particularly where hydropower can be stored behind dams, hydropower will play a major role. Increased operational flexibility of nuclear plants will also be important. But in many countries dispatchable gas turbines running at low utilisation are likely to play a major role, with a choice between:

- Burning green hydrogen produced via electrolysis when electricity supply exceeds demand.
- Continuing to burn methane but with CCS attached.
- Burning unabated gas on a very limited basis with residual emissions offset via carbon removals.

Hydrogen combustion in gas turbines

The cost elements involved for an ultra-long duration storage system based on hydrogen are illustrated in Exhibit 1.38 below.

Exhibit 1.38

Economics and costs of hydrogen production, storage and electricity generation

	Hydrogen production via electrolysis	Hydrogen storage in salt cavern	Electricity generation via OCGT
Capital Costs (2050)	• China: \$320/kW • Ex-China: \$870/kW	• China: \$25/kg$_{H2}$ capacity • Ex-China: \$40/kg$_{H2}$ capacity	• China: \$700/kW • Ex-China: \$760/kW
Operating Costs (fixed and variable, excluding fuel costs)	• 1.5% of capital costs	\$0.15-0.20/kg$_{H2}$ throughput/y	• China: \$4/kW/y, \$0.005/kWh • Ex-China: \$17/kW/y, \$0.003/kWh
Efficiency (%)	• 2030: 60% LHV (72% HHV) • 2050: 71% LHV (84% HHV)	100%[B]	40%
Lifetime (years)	25[A]	20	30

NOTE: [A]Electrolyser stacks need to be replaced during the plant lifetime, with typical stack lifetimes of around 80,000h. [B]Hydrogen storage efficiency losses are ignored in this analysis, due to the high uncertainty and small impact on the overall system generation costs. OCGT refers to open cycle gas turbine.

SOURCE: BNEF (2024), *Electrolysis System Cost Forecast 2050: Higher for Longer*; BNEF (2025), *LCOE Data Viewer*; Liu et al. (2021), *Development status and prospect of salt cavern energy storage technology.*

The total cost reflects the combination of:

Electrolyser CAPEX and utilisation: Costs of electrolyser systems have not fallen at the rapid pace anticipated five years ago, and projections of future cost have increased as analysts have developed a better understanding of the complex balance of system requirements in electrolyser systems. But costs are much lower in China than elsewhere, and progress in developing standardised and modularised designs may drive further reduction. We have assumed 2050 costs of $870 per kW for a complete system outside China, and $320 per kW in China.[126] This implies that if ex-China companies are willing to purchase their systems from China, including using Chinese EPC capabilities, the ex-China costs might fall significantly below our assumption.

The resulting annualised CAPEX and OPEX costs depend on the electrolyser utilisation rate. If they are only used 10% of all hours per annum, annualised CAPEX and OPEX costs for the ex-China case could be $7 per kg or $210 per MWh_{H2}[127] but at a utilisation rate of 50% this would fall to $1.4 per kg and $40 per $MWh_{H2.}$[128] Improving electrolyser utilisation is therefore critical to cost effectiveness. One promising strategy is to locate electrolysers within industrial clusters, where co-located offtakers and shared hydrogen infrastructure can enable higher load factors and reduced delivery costs. For example, the East Coast Cluster in the UK is pursuing co-developed low-carbon hydrogen and storage infrastructure alongside major industrial users and carbon capture hubs, helping to lower costs and aggregate demand risk for electrolyser investment.[129]

Electrolyser efficiency and electricity input costs: Many existing electrolysis systems operate at around 50–60% efficiency based on hydrogen's lower heating value (LHV), which measures the usable energy content excluding the heat recoverable from water vapor condensation. Efficiencies above 70% (LHV) are achievable and are expected to become standard by 2050; this is equivalent to ~48 kWh of electricity input per kg of hydrogen. For our estimates, we have assumed 60% LHV efficiency (equivalent to 72% higher heating value, HHV) by 2035, rising to 71% LHV (84% HHV) by 2050.[130] If the cost of electricity were $70 per MWh, an efficiency rate of 71% would imply electricity input cost of $99 per MWh_{H2} or $3.2 per kg. But if electricity is used only when supply is an excess of demand, and wholesale prices very low or even negative, the electricity input cost would be close to zero.

Exhibit 1.39 shows the resulting cost of hydrogen production for different combinations of CAPEX, electrolyser utilisation rate, and electricity input cost. In our estimates of total LCOS for 2050 we have used the sensitivities indicated as A and B in the table. These reflect the trade-off between:

- Running electrolyses at a low utilisation rate of 20%, but with the electricity input cost potentially very low or zero.
- Running them at a higher utilisation rate of 50%, but with an electricity input cost of $70 per MWh.

Storage in salt caverns: Storage in salt caverns, with 12 cycles of storage and discharge per year, is estimated to cost about $0.35–0.60 per kg, or $11–18 per MWh for 2035–2050 estimates.[131] Even major changes in the underlying assumptions would not change the conclusion that hydrogen storage costs are a small part of total system costs.

Gas turbine capex, utilisation and efficiency: The cost per MWh of reconverting the hydrogen to electricity in gas turbines depends on:

- The CAPEX and utilisation rate of the gas turbines: if the turbines are only used for <500 hours per annum (5% of all hours), which is an upper bound for our estimated need for ultra-long duration balancing, the annualised CAPEX cost could contribute $170 per MWh (Ex-China 2050) and $160 per MWh (China 2050) to the cost of electricity delivered.
- Their efficiency, with OCGT achieving efficiencies of about 40%, while CCGT can achieve 60%. This means that an OCGT needs to use 2.5 MWh_{H2} of H_2 input to produce a MWh of electricity, and a CCGT 1.67 times.

Despite their low efficiency, OCGTs will still be the economic solution if utilisation rates are very low, given their higher flexibility and lower capital cost per kW than CCGTs. CCGTs could become the economic option if utilisation rates are someone higher, for instance if the turbines were used to meet medium-duration as well as ultra-long duration balancing needs. In our estimates below we assume the OCGT option.

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[126] Systemiq analysis for the ETC; BNEF (2024), *Electrolysis System Cost Forecast 2050: Higher for Longer*. Ex-China electrolyser systems are assumed to source stack and non-stack equipment from China (i.e. using Chinese component CAPEX estimates with an uplift for transportation), and other CAPEX items, including EPC, utilities, storage and compression are assumed to be sourced locally.

[127] 1 kWh of hydrogen (denoted as kWh_{H2}, LHV here, using hydrogen's lower heating value (LHV) of 33.3 kWh per kg) is not equivalent to 1 kWh of electricity, due to the difference in useful energy (or exergy) that each form of energy can provide. The conversion efficiency of 1 kWh of hydrogen to electricity is 40–60% using an OCGT or CCGT, therefore 1 kWh of hydrogen is approximately equivalent to 0.4–0.6 kWh of electricity.

[128] This is the cost per kWh of chemical energy in the H_2; Converting this to electricity will involve efficiency losses which increase the cost of electricity finally delivered.

[129] East Coast Cluster (2021), *Cluster Plan Submission to UK Government: Delivering Decarbonisation Through Hydrogen and CCS.*

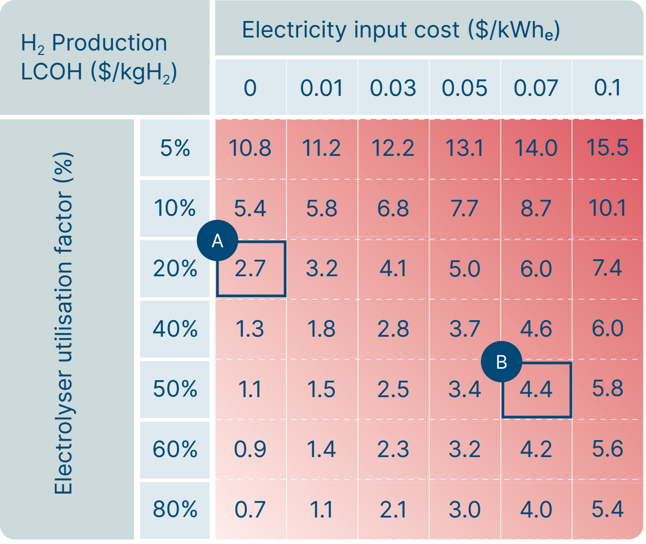
[130] BNEF (2024), *Electrolysis System Cost Forecast 2050: Higher for Longer.*

[131] Liu et al. (2021), *Development status and prospect of salt cavern energy storage technology.*

Exhibit 1.39

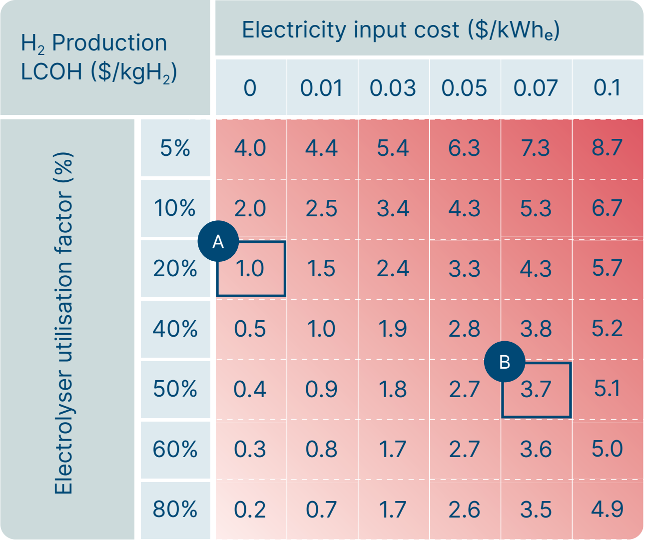
Hydrogen production costs are highly sensitive to electrolyser utilisation and electricity prices

Utilisation and electricity cost matrix, assuming $870/kW CAPEX
LCOH, $/kg$_{H_2}$



H_2 Production LCOH ($/kg$H_2$)		Electricity input cost ($/kWhe)					
		0	0.01	0.03	0.05	0.07	0.1
Electrolyser utilisation factor (%)	5%	10.8	11.2	12.2	13.1	14.0	15.5
	10%	5.4	5.8	6.8	7.7	8.7	10.1
	20%	A 2.7	3.2	4.1	5.0	6.0	7.4
	40%	1.3	1.8	2.8	3.7	4.6	6.0
	50%	1.1	1.5	2.5	3.4	B 4.4	5.8
	60%	0.9	1.4	2.3	3.2	4.2	5.6
	80%	0.7	1.1	2.1	3.0	4.0	5.4

Utilisation and electricity cost matrix, assuming $320/kW CAPEX
LCOH, $/kg$_{H_2}$



H_2 Production LCOH ($/kg$H_2$)		Electricity input cost ($/kWhe)					
		0	0.01	0.03	0.05	0.07	0.1
Electrolyser utilisation factor (%)	5%	4.0	4.4	5.4	6.3	7.3	8.7
	10%	2.0	2.5	3.4	4.3	5.3	6.7
	20%	A 1.0	1.5	2.4	3.3	4.3	5.7
	40%	0.5	1.0	1.9	2.8	3.8	5.2
	50%	0.4	0.9	1.8	2.7	B 3.7	5.1
	60%	0.3	0.8	1.7	2.7	3.6	5.0
	80%	0.2	0.7	1.7	2.6	3.5	4.9

Ⓧ Sensitivities carried forward ● Lowest sensitivity ● Highest sensitivity

NOTE: A 2050 electrolyser efficiency of 71% lower heating value (LHV), has been assumed across both matrices. Black borders identify utilisation / cost scenarios A and B that have been carried forward in the LCOS analysis. Scenarios A and B (highlighted with black borders) represent the utilisation and electricity input cost combinations used in the LCOS analysis, with Scenario A reflecting zero-cost electricity and 20% electrolyser utilisation (surplus renewables), and Scenario B representing a $0.07/kWh$_e$ electricity cost with 50% utilisation (dedicated renewables and electrolyser setup).

SOURCE: BNEF (2024), *Electrolysis System Cost Forecast 2050: Higher for Longer.*

Total cost estimates: Given the multiple different factors considered above, estimates of the full system LCOS for hydrogen production, storage, and gas turbine reconversion, have a wide range. In Exhibits 1.40 and 1.41 we show estimates for 2035 and 2050, for both China (low electrolyser costs) and ex -China (high electrolyser costs) with two different scenarios for electricity price and electrolyser utilisation:

- Exhibit 1.40 shows what the costs would be if electrolysers were used only 20% of the time, but with a zero input electricity cost. In this case the total costs are dominated by the CAPEX and OPEX of the two lightly-used capital assets – the electrolysers and the gas turbines.
- Exhibit 1.41 shows results assuming a 50% electrolyser utilisation rate, but with an input electricity cost of $70 per MWh. In this case, the contribution of electrolyser CAPEX and OPEX to total delivered electricity costs are lower, but there is a large impact of electricity input costs, as a result of the efficiency losses in both electrolysis and combustion.

Total calculated LCOS for 2050 lies in the range $270–480 per MWh in China and $460–580 per MWh in ex-China. The impacts on total system generation and balancing costs for each regional archetype are discussed in Section 1.6.

These estimates reflect the levelised cost of hydrogen-based production, storage and combustion in a situation where the assets are used solely for power balancing. But, costs might be significantly reduced if hydrogen electrolysers and storage infrastructure were co-located with industrial hydrogen demand. In industrial clusters, hydrogen produced during periods of low electricity prices can serve dual roles: meeting steady industrial off-take and providing ultra-long duration balancing for the power system during rare periods of supply scarcity. These synergies can increase electrolyser utilisation and reduce the overall system cost of decarbonisation across power and industry.

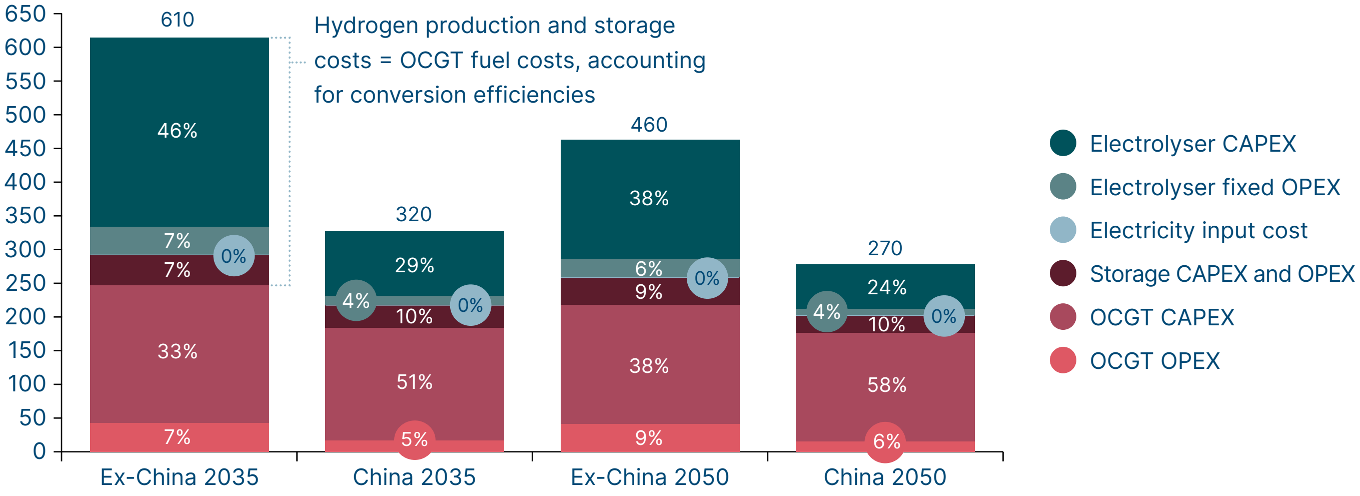
It is worth noting that, while this modelling assumes green hydrogen as the input for H_2-fired generation, gas-based hydrogen production (so-called “blue hydrogen”) could in some contexts offer a more cost-competitive alternative.

Exhibit 1.40

Hydrogen roundtrip LCOS drivers – Scenario A: 20% electrolyser utilisation factor and $0/kWh electricity

Full LCOS drivers, spanning hydrogen production, storage, and gas turbine reconversion

$/MWh$_e$



Hydrogen production and storage costs = OCGT fuel costs, accounting for conversion efficiencies

NOTE: OCGT OPEX accounts for fixed and variable OPEX, excluding fuel costs as the OCGT fuel costs are the total H_2-related costs. Hydrogen transportation costs have been ignored, assuming co-located production, storage and electricity generation. Consistent assumptions across scenarios include electrolyser efficiency of 71% (LHV), $0/MWh electricity, 20% electrolyser utilisation, 12 storage cycles per year, and 5% OCGT utilisation.

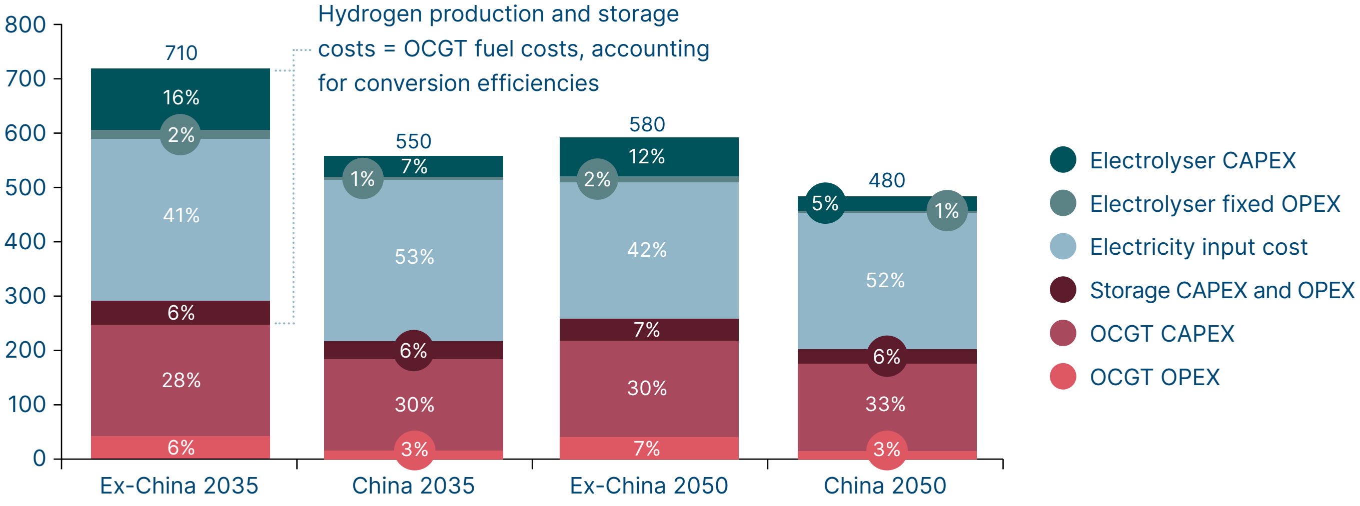
SOURCE: Systemiq analysis for the ETC: BNEF (2024), *Electrolysis System Cost Forecast 2050: Higher for Longer*; BNEF (2025), LCOE Data Viewer; Liu et al. (2021), *Development status and prospect of salt cavern energy storage technology.*

Exhibit 1.41

Hydrogen roundtrip LCOS drivers – Scenario B: 50% electrolyser utilisation factor and $0.07/kWh electricity

Full LCOS drivers, spanning hydrogen production, storage, and gas turbine reconversion

$/MWh$_e$



Hydrogen production and storage costs = OCGT fuel costs, accounting for conversion efficiencies

NOTE: OCGT OPEX accounts for fixed and variable OPEX, excluding fuel costs as the OCGT fuel costs are the total H_2-related costs. Hydrogen transportation costs have been ignored, assuming co-located production, storage and electricity generation. Consistent assumptions across scenarios include electrolyser efficiency of 71% (LHV), $70/MWh electricity, 50% electrolyser utilisation, 12 storage cycles per year, and 5% OCGT utilisation.

SOURCE: Systemiq analysis for the ETC: BNEF (2024), *Electrolysis System Cost Forecast 2050: Higher for Longer*; BNEF (2025), LCOE Data Viewer; Liu et al. (2021), *Development status and prospect of salt cavern energy storage technology.*

Blue hydrogen production can avoid the low utilisation risk faced by electrolysers, as it can be produced steadily from natural gas with carbon capture and provided for other, more ‘baseload’ hydrogen users such as in refining, with any excess being stored. This could reduce the overall levelised cost of electricity from hydrogen-fuelled CCGTs, particularly where blue hydrogen production is co-located with CO_2 storage infrastructure, with the UK already investing into projects such as these.[132] However, in order to be a truly low-carbon source of hydrogen, upstream methane leakage must be below 0.1–0.2%, and CO_2 capture rates close to 100%, as even small leakage levels can significantly undermine the climate benefits of blue hydrogen (reference needed for the sentence here - For a detailed assessment of the environmental risks associated with blue hydrogen.[133]

Burning methane in gas turbines with CCS applied

An alternative way to achieve ultra-long duration balance would be to continue burning methane in gas turbines, adding CCS to achieve net-zero emissions. In this case, as shown in Exhibit 1.44:

- Annualised CAPEX and OPEX costs resulting from gas turbines used for only a small percentage of hours would be significant, but lower than in the hydrogen option due to less expensive turbines.
- This option avoids the requirement for electrolysers but instead requires the addition of CCS equipment which would have the same very low utilisation rate as the gas turbines.
- The primary energy input would be gas, rather than electricity.
- The effective system efficiency would reflect the baseline efficiency of a gas turbine (approximately 60% for CCGTs[134] or 40% for OCGTs[135]), reduced by the parasitic electricity load of the carbon capture process (e.g., equivalent to approximately 10–15% of the electricity generated).[136]

The lower cost of the gas plus CCS route is also highlighted in Exhibits 1.32 to 1.34, which show our 2035 cost estimates. Methane-fired CCGTs with CCS is likely to be a lower-cost option than burning hydrogen in gas turbines, with levelised costs in the range of $200–270 per MWh (this assumes a higher utilisation of 10% to reflect the higher expected utilisation of CCGTs compared to OCGTs which are assumed to operate more flexibly at 5% utilisation).[137] However, hydrogen could still prove the more attractive solution if electrolyser costs fall more rapidly than assumed, and high utilisation rates can be achieved by serving multiple markets, or in countries facing high natural gas prices.

Exhibit 1.42

Economics and costs of CCGT and CCS

Electricity production via CCGT + **CCS**

Capital Costs (2050)	• China: $850/kW • Ex-China: $932/kW
Fixed Operating Costs (2050)	• China: $5/kW/year • Ex-China: $20/kW/year
Variable Operating Costs (2050)	• China: $0.07/kW/year • Ex-China: $0.06/kW/year
Lifetime (years)	• 30

NOTE: CCGT refers to combined cycle gas turbine and CCS refers to carbon, capture, storage.

SOURCE: BNEF (2025), *LCOE Data Viewer.*

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132 UpstreamOnline (2024), *Massive boost for blue hydrogen as UK government greenlights £22 billion for two carbon capture clusters*

133 For a detailed assessment of the environmental risks associated with blue hydrogen, see Bertagni, M., Weber, T., & Dittmeyer, R. (2022). *Risk of the Hydrogen Economy for Atmospheric Methane;* Hydrogen Science Coalition; and ETC’s report *Making the Hydrogen Economy Possible* for additional LCOE analysis and system roles for hydrogen.

134 Ipieca (2022), *Combined-cycle gas turbines.* Available at https://www.ipieca.org/resources/energy-efficiency-compendium/combined-cycle-gas-turbines-2022. [Accessed January 2025].

135 Wang et al. (2019), *Performance evaluation of open cycle gas turbines in different market scenarios, Energy Policy*.

136 Global CCS Institute (2011), *CO_2 Capture Technologies – Post Combustion Capture (PCC).*

137 Using an assumed gas price of $6/MMBtu. See BNEF (2025), *LCOE Data Viewer.*

In addition, it is important to note that while it is technically feasible to operate at CCS equipment at low utilisation rates, some studies suggest that capture systems become less efficient under these conditions. When operating at half capacity, the energy cost of capturing CO_2 can increase by over 20%, making the plant less efficient and more expensive to run.[138] In addition residual emissions also remain, both from upstream fossil fuel extraction and transportation, and from limitations on achievable capture rates. It is therefore important to ensure, via carbon pricing and regulation, that these emissions are taken into account in the choice between hydrogen and gas + CCS routes.[139]

Last mile decarbonisation: Offsetting unabated gas use with carbon removals

Whatever solution is chosen, the cost per MWh shifted is likely to be significantly higher for ultra-long duration than the least cost options for short and medium-long duration. And while the total system cost impact is kept low by the small percentage of all hours that need to be shifted, the implication is that the "last mile" of power system decarbonisation will be the most expensive, and especially so in high latitude countries.

This raises the question of whether these costs could be reduced by stopping short of complete power system decarbonisation and instead offsetting small residual emissions via the use of carbon removals (whether nature-based or engineered).

Exhibit 1.43 presents a highly illustrative comparison of two ways the UK could meet its ultra-long duration balancing need in a low-wind year, using gas turbines. The analysis assumes that 15 TWh of demand annually must be met by turbine-based generation during 130 hours in which wind and solar supply almost no power. The analysis also showcases the estimated impact on an average household bill of each technology, with incremental bill impacts shown relative to the 2024 average wholesale price benchmark and all non-wholesale bill components held constant. Impacts are modelled on the household portion of bills, while assuming the underlying cost is spread evenly across all electricity bill payers.[140]

- This would require an increase in total turbine capacity from today's 36 GW to 115 GW, operating with a 1.5% capacity factor.[141]
- The cost of electricity delivered from hydrogen electrolysis and turbines at a very low utilisation rate could be as high as £740 per MWh ($950 per MWh). The annual UK household bill impact could be an additional £125 ($160) compared to a scenario using existing gas turbines with no abatement.[142]
- However, if new unabated OCGT gas turbines are used with an LCOS of £520 per MWh ($665 per MWh) the per household cost falls to £80 per year ($100), due to lower capital and fuel costs. However, this scenario would leave the power system still producing 6 million tonnes of CO_2 emissions per annum.

These residual emissions could be offset by carbon removals separate from the power system. The ETC's 2021 report on carbon removals, Mind the Gap explored likely future costs of both nature-based and engineered carbon removals, along with the associated risks relating to permanence and certainty. It suggested that the costs of permanent and certain engineered removals via direct air carbon capture (DACC) might eventually fall from today's $300 –600 per tonne of CO_2 to $100[143] by 2050. Recent research from MIT suggests however that these current cost projections may be underestimates, especially when factoring in infrastructure, energy supply, and real-world deployment conditions.[144] However, if DACC costs did fall to $200 per tonne, pursuing unabated gas with DACC could be slightly less costly for households in the UK, at £90 per household.[145]

This would leave the UK with a power system which would not be absolutely zero carbon. However, 15 TWh would represent just 2.5% of likely total generation of around 600 TWh in 2050 and this would leave the UK power system with a carbon intensity of electricity of just 10g per kWh vs. 500g in 2010 and 125g in 2024, thus achieving 98% power system decarbonisation vs. the fossil fuel dominated system of 2010. The option of continuing to run a very small share of unabated gas offset by carbon removals should therefore not be excluded.

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[138] Verhaeghe et al. (2022), *Carbon Capture Performance Assessment Applied to Combined Cycle Gas Turbine Under Part-Load Operation.*

[139] E3G (2023), *Carbon Capture and Storage Ladder.*

[140] Impacts were estimated by adjusting the 2024 average wholesale electricity price (based on Ember, *European Wholesale Electricity Price Data.* Available at https://ember-energy.org/data/european-wholesale-electricity-price-data/. [Accessed January 2025].) using LCOEs for hydrogen, CCS and unabated gas used for balancing. These adjusted prices were applied to the average UK household electricity bill structure (with fixed network, policy, and other charges held constant) to calculate absolute and percentage bill increases for each technology scenario.

[141] The 15 TWh figure reflects the estimated annual electricity output required from H_2-ready CCGTs to meet long-duration balancing needs in a UK 2050 scenario. It is derived from modelled peak deficits occurring during periods of extremely low wind and solar generation, when other flexible resources are unavailable. This value aligns with system balancing modelling conducted for low-wind and solar periods and assumes an adjusted 1.5% annual capacity factor, consistent with the infrequent but critical nature of ultra-long duration dispatch.

[142] Assumptions here include: an electrolyser utilisation factor of 20%, H_2 storage with 12 cycles per annum, and an OCGT utilisation rate of 1.5% to align with the low utilisation modelling in this particular example. These household cost estimates reflect the full system cost of delivering 15 TWh of balancing energy, spread across 30 million households and adjusted for the share of electricity in total energy demand. They are used as a way to illustrate the comparative cost burden of different decarbonisation pathways.

[143] ETC (2021), *Mind the Gap: How Carbon Dioxide Removals Must Complement Deep Decarbonisation to Keep 1.5°C Alive.*

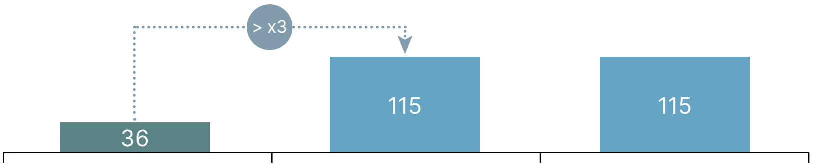
[144] Source: New Power (2024), *Direct air capture cost has been underestimated, say MIT researchers.*

[145] Same model used in Exhibit 1.43 applied here where the wholesale portion of household consumer bills in 2024 to note the increasing cost of using DACC. See exhibit to note assumptions and sources.

Exhibit 1.43

Illustrative example: Sizing ultra-long duration balancing options to meet highest deficit peak in UK low-wind year would be very high cost

Capacity today vs. capacity required in to fully meet max peak of ultra long-duration balancing
GW



	Gas capacity in UK in 2024	H$_2$-ready OCGT's	New OCGT's
Annual TWh of generation	101	15	15
Levelised cost ($/MWh)	N/A (existing)	740 £/MWh	520 £/MWh for new assets
Estimated increase in annual household electricity bill	N/A	£125	£80
Annual emissions (MtCO$_2$e)	~40 MtCO$_2$e	~0 MtCO$_2$e	6 MtCO$_2$e

Cost vs. emissions trade off for "last mile" decarbonisation

CCGT + CCS ruled out as unsuitable for ultra-low utilisation due to high capital costs, slow ramping, and poor pertormance of carbon capture at low loads

⋯⋯➤ Portfolio of options best way to deliver lowest cost last mile decarbonization?

NOTE: We estimate the impact of ultra-low-utilisation peaking generation on consumer bills by modelling 15 TWh of electricity generation per year delivered by different peaking technologies. To determine the required installed capacity, we assume a **1.5% capacity factor**, reflecting the very low utilisation expected of last-mile balancing assets used only during periods of system stress. For H$_2$-ready peakers, a hydrogen cost of $2.70/kg in 2050 (excluding storage) is assumed. Emissions from unabated gas are based on an intensity of 0.394 kgCO$_2$e per kWh, as reported by the UK Department for Environment and Net Zero. We then estimate the increase in average wholesale electricity price resulting from substituting this 15 TWh of generation with each peaking technology. That wholesale price uplift is applied to the wholesale component of a representative 2024–25 household bill (£311 out of a total £913; see Exhibit 3.4), holding all other components (network, policy, and supplier costs) constant. This isolates the incremental impact on household bills caused specifically by the higher cost of peaking generation.

SOURCE: Systemiq analysis for the ETC: BNEF (2025), *Levelised Cost of Electricity 2025 Updates*; BNEF (2025), *LCOE Data Viewer*, Ben James (2025), *Electricity Bills*; Ofgem (2024), *Wholesale cost allowance methodology Annex 2*; Ember (2025), *Electricity Data Explorer.* Available at https://ember-energy.org/data/electricity-data-explorer/. [Accessed January 2025].

Conclusions on ultra-long duration balancing

Overall it is clear that balancing supply and demand across ultra-long durations will be the most difficult challenge in power system decarbonisation, particularly in high latitude wind belt countries. Technologies exist which can solve the challenge (in many countries involving the continued use of gas turbines), and the impact on total system costs is limited by the small percentage of supply which needs to be shifted across ultra-long duration, but this still leaves the "last mile" of power sector decarbonisation the most expensive.

This perspective is supported by wider research,[146,147,148] which shows that the marginal cost of achieving the final 5–10% of power sector decarbonisation might in some cases be high relative to the emissions reduction benefit.

A pragmatic approach to the ultra-long duration challenge should therefore be pursued, one that reflects the future evolution of costs across different decarbonisation options and does not exclude the possibility of limited continued use of unabated gas, provided it is offset by certified carbon removals. If this option is pursued, its use must be governed by strict safeguards to prevent overreliance or misuse, foremost among them the implementation of robust and enforceable carbon pricing to ensure emissions are appropriately accounted for and disincentivised. In parallel, governments should assess the relative cost effectiveness of power sector decarbonisation strategies aimed at eliminating the final residual emissions, compared to those that accelerate electrification across the wider economy once the power system has already achieved very low carbon intensity.

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[146] NREL (2021), *The Challenge of the Last Few Percent: Quantifying the Costs and Emissions Benefits of 100% Renewables.*

[147] Columbia SIPA Center on Global Energy Policy (2018), *Getting to Zero Carbon Emissions in the Electric Power Sector.*

[148] Conlon, T., Waite, M., Wu, Y., & Modi, V. (2022), *Assessing Trade-Offs Among Electrification and Grid Decarbonization in a Clean Energy Transition: Application to New York State.*

1.6 Total system generation and balancing costs

The total system generation and balancing costs are given by the cost of generation itself (the levelised cost of producing a kWh of electricity from either renewable or other sources), plus the cost of storage or other forms of balancing. The latter is determined by the cost per kWh of balancing for different durations, multiplied by the number of hours that need to be shifted.

In this section, we present estimates of what the total system generation and balancing costs might be for four different archetypes in the period post-2050, under the following unrealistic assumptions:

- 100% of electricity supply is ultimately provided by wind and solar (though with some converted to hydrogen and then burned in gas turbines to meet the ultra-long balancing challenge).
- The systems are effectively built anew in 2050, such that the relevant costs are those projected for each technology in that year.
- Outside of the short-duration balancing costs, there is no allowance for the potentially low-cost or costless benefits of demand side flexibility, nor for the potential for low-cost supply or balancing via long-distance transmission.

While these are unrealistic assumptions, the results help to illustrate how the balancing challenge and resulting costs vary by region.

To develop more realistic estimates of total generation and balancing system costs in 2050, it is essential to use dispatch models that simulate in detail how the system balances over the course of the year, ideally in half-hourly (or shorter) time intervals. We have therefore compared our results with those produced by dispatch models for the different regions. The following factors could lead dispatch model results to be either higher or lower than our illustrative estimates:

- Lower than 100% shares of wind and solar supply, allowing for the use of hydro, nuclear, or other zero-carbon sources. If these are cheaper than wind and solar, costs may be lower than our illustrative estimates. Additionally, including gas + CCS as a potentially lower cost technology for ultra-long duration flexibility. For example, in the CCC's modelling for the Seventh Carbon Budget, ultra-long balancing is primarily met by gas-fired generation with CCS, not by hydrogen as in the ETC's modelling.
- Allowance for demand side flexibility in the medium-long balancing challenge, which tends to reduce estimated costs – while we have factored demand side flexibility as a low-cost technology option in short duration balancing, there remains potential for DSF technologies to be used in longer duration balancing to lower the total system costs shown below.
- Greater granularity in balancing analysis, including different approaches to the trade-off discussed in Section 1.3 between the higher costs of oversizing wind and solar supply and the resulting reduction in balancing needs. This could raise or lower system costs.
- Alternative technology cost assumptions, which could also increase or decrease total system costs.
- Allowance for the "legacy" costs of more expensive contracts (e.g., renewable contracts for difference or renewable obligation certificates) entered into before 2050, which may have higher prices than new contracts signed in that year. These would increase the cost per kWh of the system.

Our illustrative estimates and dispatch model results suggest that:

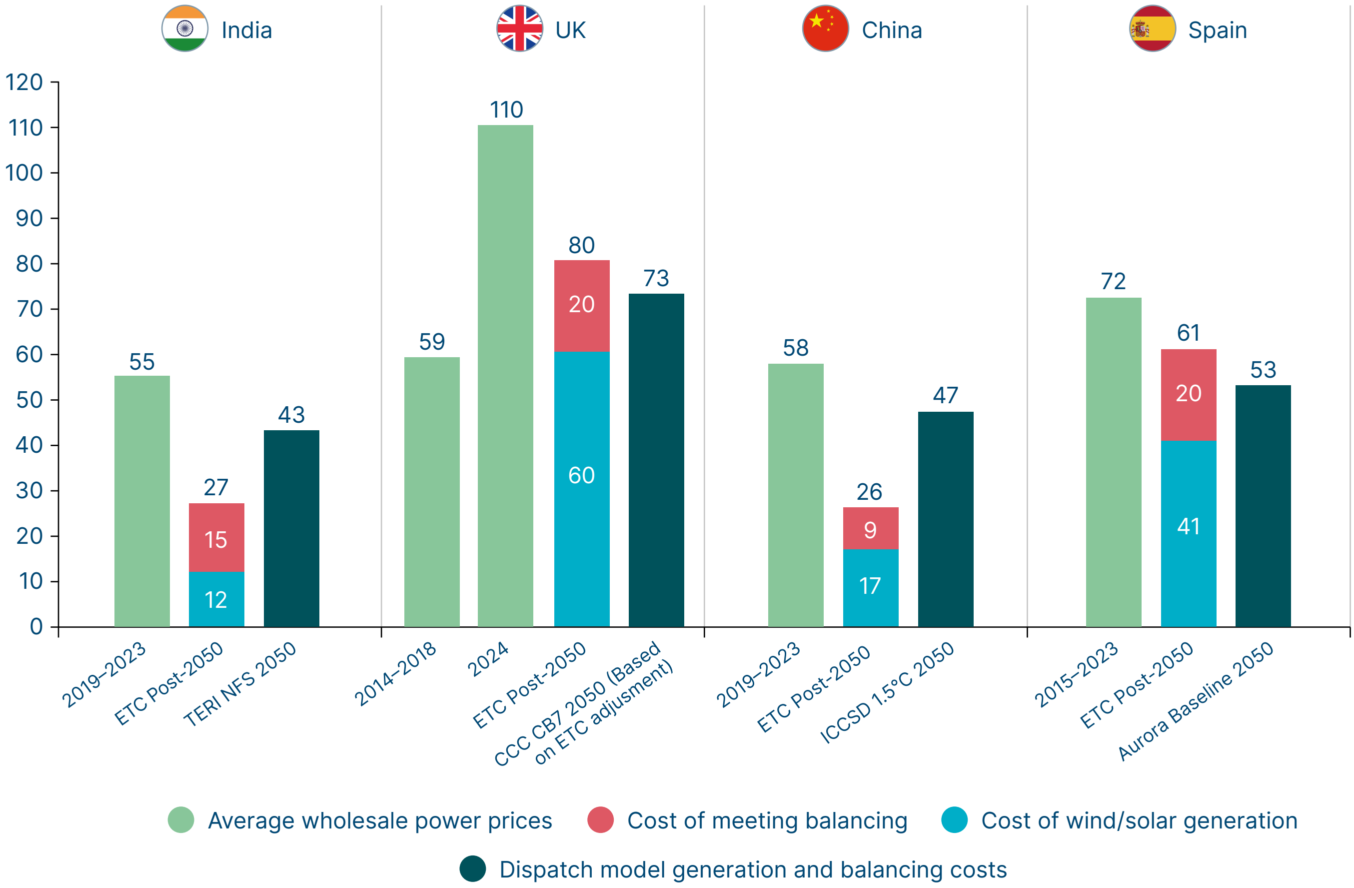
- It will be possible to build systems with high shares of variable renewables that generate electricity in 2050 and beyond at costs similar to - or in some cases below - current wholesale electricity prices, as shown in Exhibit 1.44 below.
- Total system generation and balancing costs will be significantly lower in low latitude, sun belt countries than in higher-latitude, wind belt countries. This reflects both the low cost of the solar-plus-battery solution that dominates in low-latitude regions and the greater complexity of the balancing challenge in high latitude countries.

The additional costs resulting from required investments in transmission and distribution grids are considered in Chapters 2 and 3. Chapter 3 also addresses the crucial issue of costs to consumers during the transition to the end point considered here.

Exhibit 1.44

Total system generation and balancing costs are likely to be lower than today's wholesale prices

Total system generation and balancing, recent vs. post-2050
$/MWh (real 2024$)



SOURCE: Systemiq analysis for the ETC; BNEF (2025), *LCOE: Data Viewer;* Ofgem (2025), *Wholesale market indicators – Electricity Prices: Forward Delivery Contracts – Weekly Average (GB);* IEA (2023), *Electricity Market Report – Update 2023;* Statista (2024), *Average electricity prices for enterprises in China from September 2019 to September 2024;* Ember (2025), *Wholesale electricity prices in Europe;* CCC (2025), *The Seventh Carbon Budget;* TERI (2024), *India's Electricity Transition Pathways to 2050: Scenarios and Insights;* ICCSD (2022), *China's Long-Term Low-Carbon Development Strategies and Pathways;* Aurora (2023), *Long Duration Energy Storage in Spain.*

High Latitude archetype - UK Case study

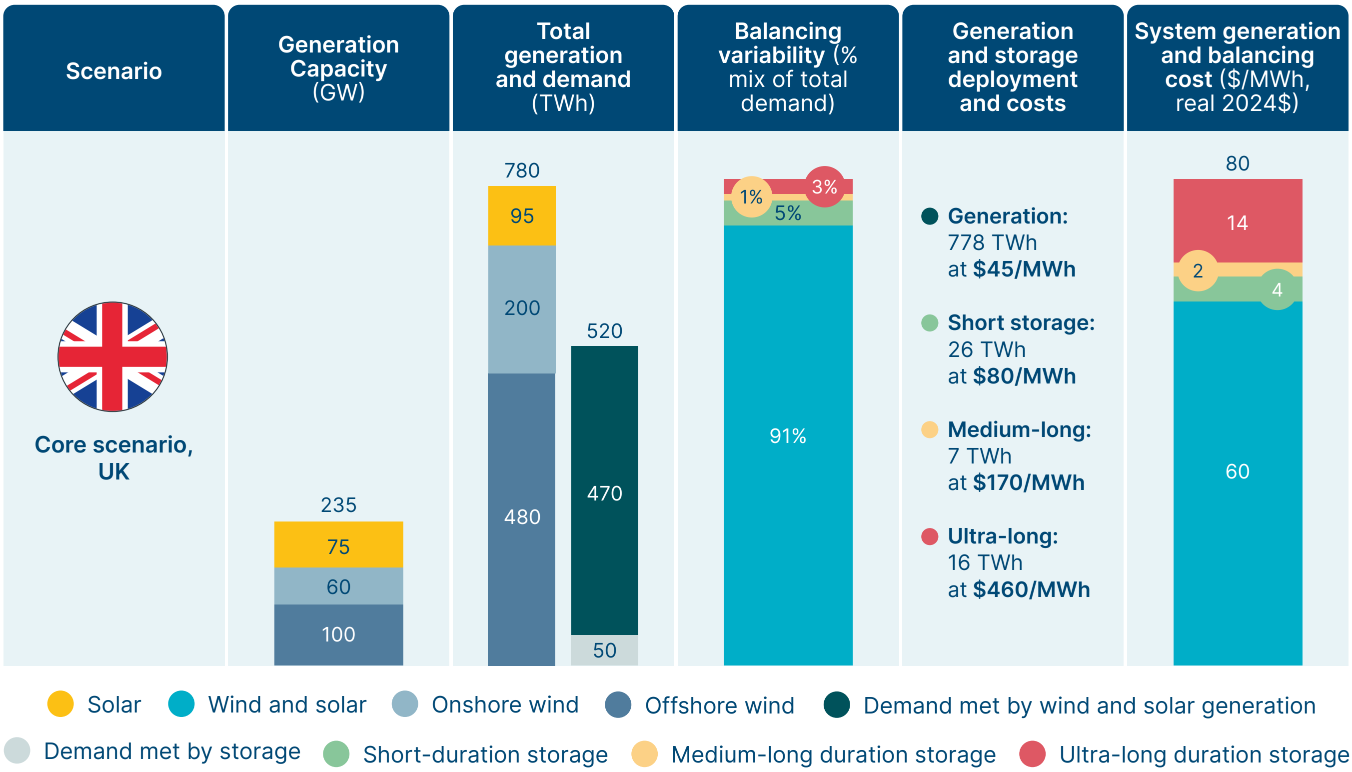
Our illustrative results for the high latitude archetype, using the UK as a case study, are shown in Exhibit 1.45. They suggest that:

- The system is heavily wind-dominated, with approximately 88% of total generation coming from offshore and onshore wind, and 12% from solar. Installed capacity is significantly oversized relative to demand, with 235 GW of renewables (comprising 100 GW offshore wind, 60 GW onshore wind, and 75 GW solar) capable of generating 778 TWh annually to meet 518 TWh of end-use demand.
- Generation costs are estimated at $45 per MWh, reflecting continued cost reductions in offshore, onshore wind, and solar. These costs are higher than those in solar-led systems, due to the relatively higher cost of offshore wind.
- Balancing requirements represent 9% of annual demand and are met through a combination of storage solutions across three durations:
  - Short-duration storage meets 5% of demand (26 TWh), at a levelised cost of $80 per MWh.
  - Medium-duration storage meets 1% of demand (7 TWh), at a cost of $170 per MWh.

Exhibit 1.45

Total system generation costs for a 2050 system, High Latitude

$/MWh (real 2024$)



NOTE: Surplus generation (the difference between demand and generation) is either curtailed or used in electrolysers. Generation costs are derived based on the generation mix using BNEF 2050 mid CAPEX and OPEX estimates, alongside capacity factors from the average weather year supply scenario (representing the long-term average), 30-year project lifetimes, and real WACC of 4%, 5%, and 6% for solar, onshore wind, and offshore wind, respectively. Storage costs are derived using the LCOS methodology outlined in this report, with the input electricity cost for all storage technologies set to be the archetype's generation cost per MWh. Efficiency losses for storage technologies are included (assumed efficiencies are 90% for short, 60% for medium-long, 40% for ultra-long). Surplus generation arises from overbuild required to meet balancing needs and is included in both energy and cost calculations. Cost estimates are in 2024 US$/MWh and reflect levelised costs of generation and storage, including contributions from surplus energy.

SOURCE: Systemiq analysis for the ETC; BNEF (2025), *LCOE: Data Viewer.*

  - Ultra-long duration storage covers 3% of demand (16 TWh), required for extended periods of low wind and high seasonal demand. This is modelled at $460 per MWh, based on conservative assumptions for H_2 turbines. Future innovation or regional transmission could reduce this cost, and it will be further explored in follow-on modelling. 48 TWh is an upper bound for the H_2 storage required in the minimum weather year, some of which could be met by gas (with or without CCUS), or other forms of ultra-long storage to reduce the volume required.
- Combining generation and balancing costs yields a total system generation cost of $80 per MWh. Of this, $14 per MWh, nearly 18%, is attributable to ultra-long duration storage, despite its relatively limited role in covering annual demand. This reflects the high cost of ensuring security of supply during infrequent but critical multi-day or seasonal imbalances.

Exhibit 1.46 compares our illustrative UK results with the UK Climate Change Committee's (CCC) Seventh Carbon Budget (CCC / CB7). The CCC results are based on dispatch modelling carried out by AFRY, and reflect a more diversified generation mix.

The CCC modelling estimates a total system generation and balancing cost of $73 per MWh (assuming the same grid costs as in the ETC's UK 2050 scenario, outlined in Chapter 2, to strip out grid costs), compared to $80 per MWh in the ETC scenario. Despite slightly lower overall costs in the CCC case, this difference is driven by modelling assumptions, as noted below, split by lower and higher costs:

- Diverse generation mix: Unlike the ETC scenario, which assumes a system supplied almost entirely by wind and solar, the CCC modelling includes only 82% generation from variable renewables. The remainder comes from gas with CCS (66 TWh), nuclear (79 TWh), bioenergy (35 TWh), and interconnectors (net −2 TWh). This more balanced mix reduces the need for overbuild and high-cost balancing solutions.

Exhibit 1.46

Dispatch comparison results for the UK


Total system generation and balancing costs $/MWh (real 2024)

Capacity Mix GW

Share of wind and solar %

Generation Mix TWh

NOTE: The CCC only published total system cost estimates including network costs in the 7th Carbon Budget, therefore the system generation and balancing cost above assumes the ETC's estimated grid costs per MWh, described in Chapter 3 of this report, to strip out network costs from the CCC's 2050 value. Other includes biomass (with and without CCS). CCC / CB7 assumes average capacity factors across wind and solar sources, of 33%, 47%, and 10% for onshore, offshore wind, and solar, respectively (lower than ETC's 40%, 55%, 15%), which pushes up system costs in the CCC scenario due to higher wind and solar installed capacity.

SOURCE: Systemiq analysis for the ETC; CCC (2025), *The Seventh Carbon Budget*.

- Lower-cost dispatchable backup: CCC assumes the use of both gas with CCS and hydrogen for dispatchable, ultra-long duration flexibility. This hybrid approach is less costly than ETC's assumption of relying solely on electrolytic hydrogen for low-carbon peaking power.
- Lower overbuild due to higher demand coverage: While CCC and ETC assume similar levels of total generation (~867 TWh), CCC's underlying electricity demand is higher (692 TWh vs. ETC's ~620 TWh), meaning less excess generation and curtailment, and thus lower average costs.
- Lower assumed wind LCOEs: CCC modelling reflects lower capital costs and financing assumptions for wind, leading to lower levelised costs for variable renewables, particularly offshore wind.

Other differing factors:

- While the offshore wind capacity factor in the CCC scenario appears relatively high compared to current median performance in the UK (closer to 38%), it may reflect anticipated improvements from newer sites or future technologies.[149]

Importantly, both scenarios estimate future system costs below today's average UK wholesale electricity price of ~$110/MWh (2024).[150]

Drivers of recent volatility in UK and European power prices are explored further in Section 3.2.

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[149] WattDirection Substack (2024), *UK Offshore Wind Capacity Factors — Projected vs Real-World Performance*.

[150] Ofgem, Electricity Prices: Forward Delivery Contracts – Weekly Average (GB)

Low Latitude archetype - India Case study

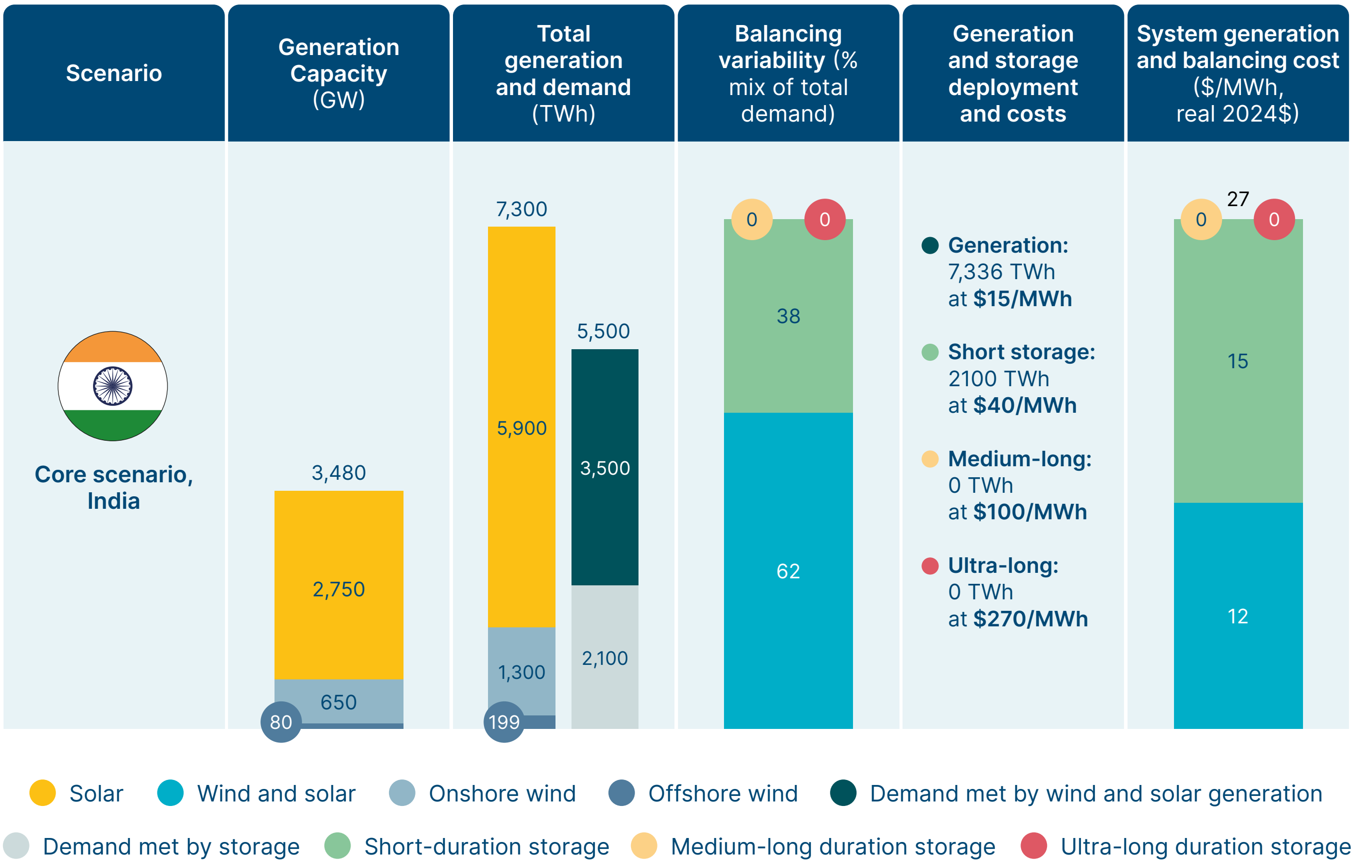
Exhibit 1.47 shows our illustrative estimates for a low latitude system archetype, using India as a case study.

- The system is 100% variable renewable, dominated by solar, which accounts for approximately 79% of installed capacity and 80% of total generation. Generation costs are projected to fall to $15 per MWh by 2050, reflecting India's high solar resource availability and continued cost reductions in PV technologies.
- Balancing requirements represent 38% of annual demand, driven primarily by daily solar variability. These are met almost entirely by short-duration storage with a capacity of 8.5 TWh (with a conversion efficiency of 90%), delivering 2,100 TWh annually at a levelised cost of $40 per MWh. No medium- or ultra-long duration storage is required in this scenario.
- The total system generation cost is estimated at $27 per MWh, with approximately $15 per MWh (over 50%) attributable to the cost of balancing supply during periods of low or no solar availability, particularly evening and night hours. This highlights the cost impact of diurnal variability, even in high-solar contexts.

Exhibit 1.47

Total system generation costs for a 2050 system, Low Latitude

$/MWh (real 2024$)



NOTE: Surplus generation (the difference between demand and generation) is either curtailed or used in electrolysers. Generation costs are derived based on the generation mix using BNEF 2050 mid CAPEX and OPEX estimates, alongside capacity factors from the average weather year supply scenario (representing the long-term average), 30-year project lifetimes, and real WACC of 4%, 5%, and 6% for solar, onshore wind, and offshore wind, respectively. Storage costs are derived using the LCOS methodology outlined in this report, with the input electricity cost for all storage technologies set to be the archetype's generation cost per MWh. Efficiency losses for storage technologies are included (assumed efficiencies are 90% for short, 60% for medium-long, 40% for ultra-long). Surplus generation arises from overbuild required to meet balancing needs and is included in both energy and cost calculations. Cost estimates are in 2024 US$/MWh and reflect levelised costs of generation and storage, including contributions from surplus energy.

SOURCE: Systemiq analysis for the ETC; BNEF (2025), *LCOE: Data Viewer.*

Exhibit 1.48 compares our illustrative results for India with those from ETC member TERI, based on its 15-minute interval dispatch model. TERI presents three scenarios - NFS (no fossil fuels), URES (unconstrained renewables), and CRES (constrained renewables) - which vary in assumptions about land availability, fossil fuel use, and the solar-wind mix. These result in wind and solar generation shares ranging from 67% to 95%, compared to 100% in the ETC case.

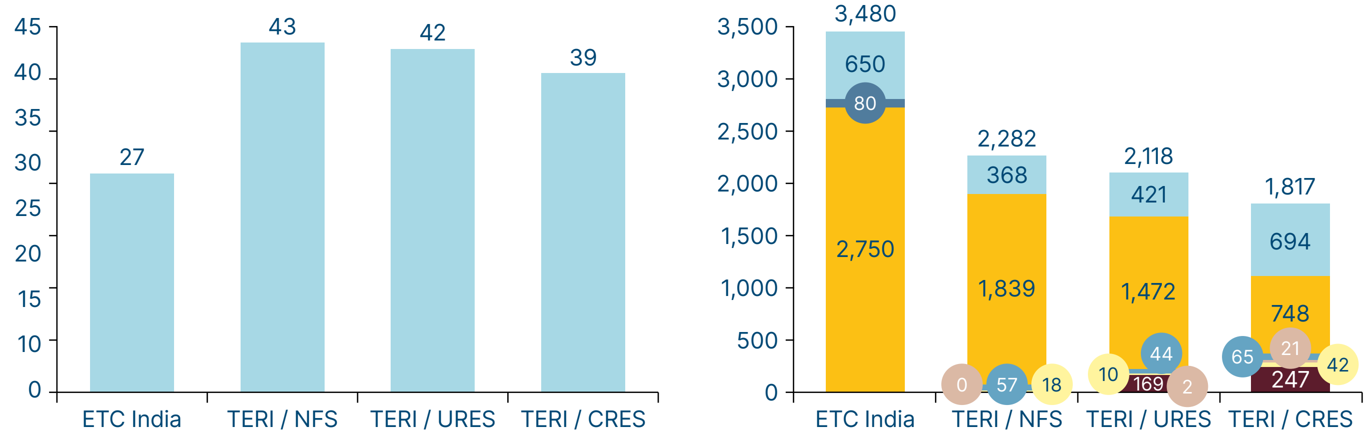
- TERI's modelling suggests total system generation and balancing costs of $39 to $43 per MWh, compared to $27 per MWh in the ETC scenario.
- The higher costs in the TERI scenarios reflect less aggressive assumptions on solar PV and battery storage cost reductions, as well as a lower total capacity factors for renewables, with the highest capacity being 97% in the NFS scenario.
- Despite these differences, all scenarios show system costs well below India's current wholesale electricity price, reinforcing the case for cost-effective decarbonisation of India's power sector.

Exhibit 1.48

Dispatch comparison results for India

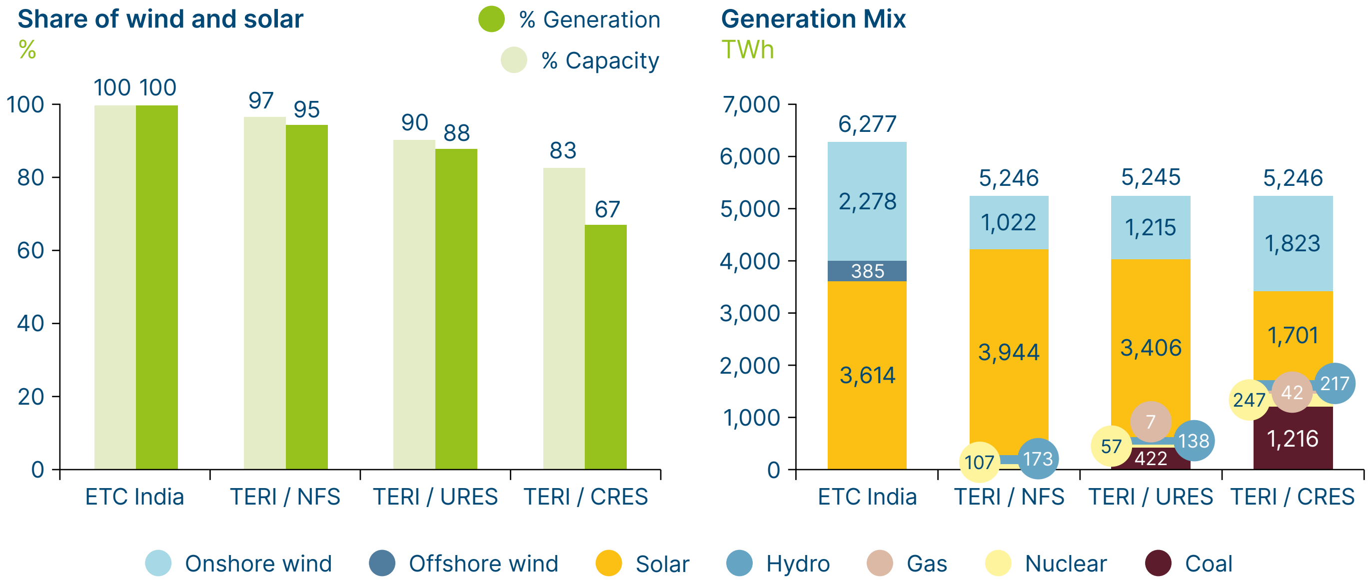
Total system generation and balancing costs
$/MWh (real 2024)

Capacity Mix
GW



Share of wind and solar
%

Generation Mix
TWh



NOTE: NFS refers to no fossil fuel scenario; URES refers to unconstrained renewable energy scenario; CRES refers to constrained renewable energy scenario. Other includes biomass (with and without CCS). TERI assumes average capacity factors across wind and solar sources, of 30–33% and 24% for onshore wind and solar, respectively (onshore wind lower than ETC's 40% assumption, while solar is higher than ETC's 15% assumption).

SOURCE: Systemiq analysis for the ETC; TERI (2024), *India's Electricity Transition Pathways to 2050: Scenarios and Insights.*

Mixed Climate archetype – China case study

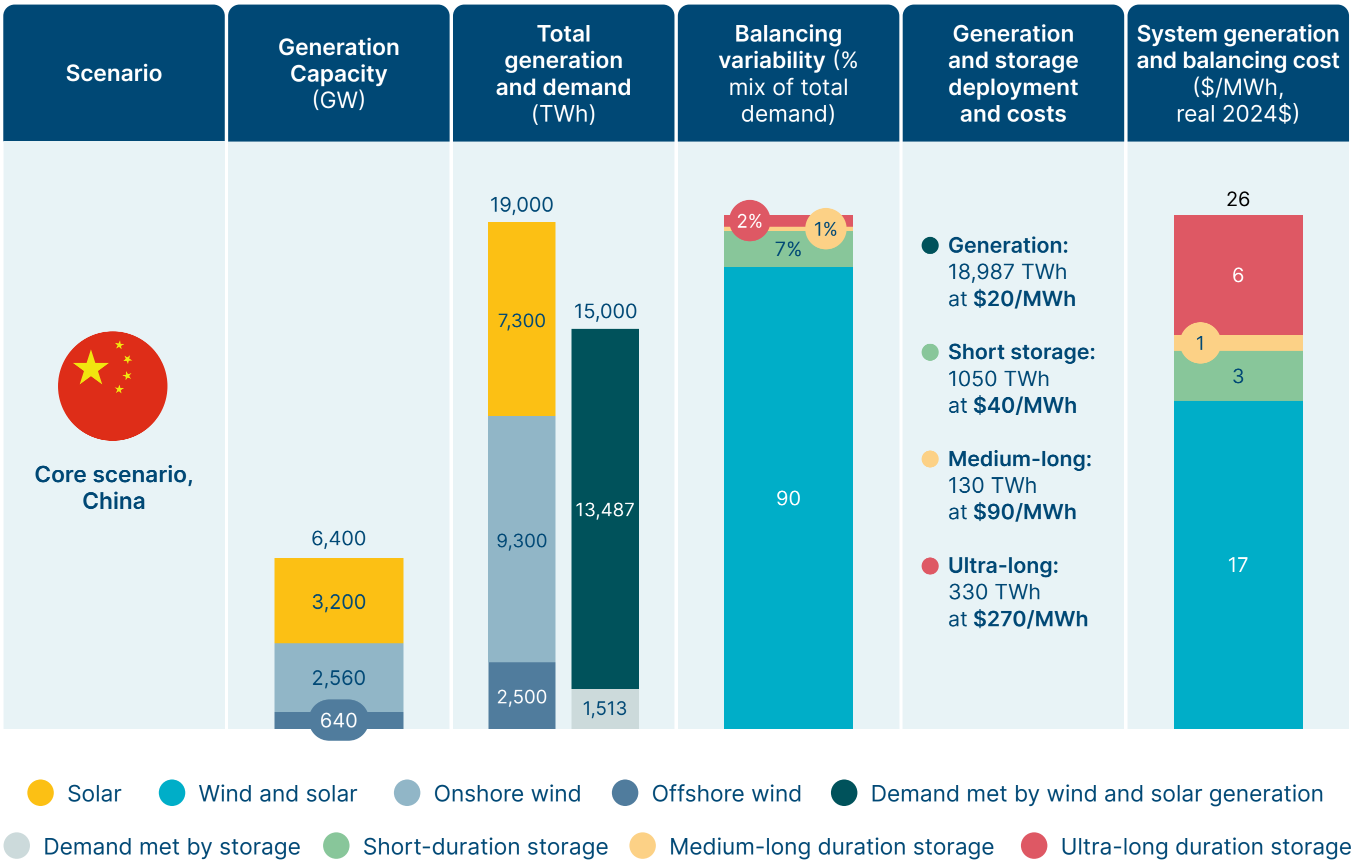
Our illustrative estimates for a Mixed Climate system archetype are shown in Exhibit 1.48, using China as a case study. This scenario results in system costs comparable to India, reflecting a balancing complexity between the Low Latitude and High Latitude archetypes, but offset by lower assumed costs for several generation and storage technologies.

- The generation mix lies between the UK and India cases, with wind accounting for 71% of total generation and solar for 29%. Total installed capacity reaches 6,400 GW, generating 18,987 TWh to meet 15,000 TWh of electricity demand.
- Generation costs are estimated at $20 per MWh, higher than in India but lower than in the UK. This reflects the availability of low-cost wind resources in regions such as Inner Mongolia and the combined contribution of both wind and solar to the system mix.
- The total system generation cost is $26 per MWh, with ultra-long duration storage contributing $6 per MWh, more than 20% of the total cost, despite covering only 2% of annual demand (330 TWh). This reflects the increased seasonal balancing challenge compared to India, requiring significant energy shifting across longer durations.

Exhibit 1.49

Total system generation costs for a 2050 system for mixed climate

$/MWh (real 2024$)

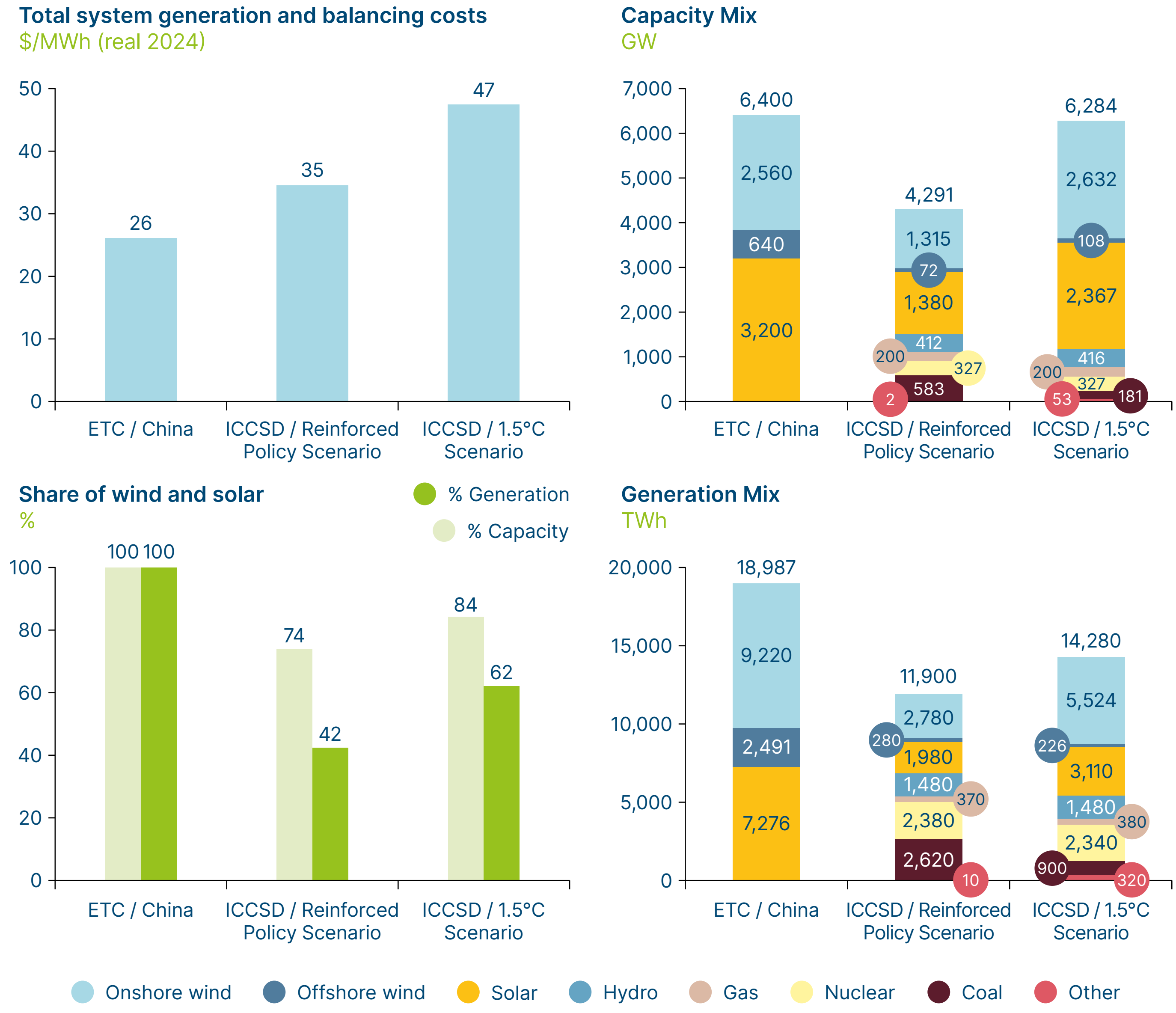


NOTE: Surplus generation (the difference between demand and generation) is either curtailed or used in electrolysers. Generation costs are derived based on the generation mix using BNEF 2050 mid CAPEX and OPEX estimates, alongside capacity factors from the average weather year supply scenario (representing the long-term average), 30-year project lifetimes, and real WACC of 4%, 5%, and 6% for solar, onshore wind, and offshore wind, respectively. Storage costs are derived using the LCOS methodology outlined in this report, with the input electricity cost for all storage technologies set to be the archetype's generation cost per MWh. Efficiency losses for storage technologies are included (assumed efficiencies are 90% for short, 60% for medium-long, 40% for ultra-long). Surplus generation arises from overbuild required to meet balancing needs and is included in both energy and cost calculations. Cost estimates are in 2024 US$/MWh and reflect levelised costs of generation and storage, including contributions from surplus energy.

SOURCE: Systemiq analysis for the ETC; BNEF (2025), *LCOE: Data Viewer.*

Exhibit 1.49

Dispatch comparison results for China



Total system generation and balancing costs
$/MWh (real 2024)

Capacity Mix
GW

Share of wind and solar
%

Generation Mix
TWh

NOTE: Other includes biomass (with and without CCS). ICCSD assumes average capacity factors across wind and solar sources, of 24%, 24–44%, and 15–16% for onshore, offshore wind, and solar, respectively (lower than ETC's 40%, 55%, 15%).

SOURCE: Systemiq analysis for the ETC; ICCSD (2022), *China's Long-Term Low-Carbon Development Strategies and Pathways.*

Exhibit 1.49 shows a comparison of our illustrative modelling for China with results from ETC member Institute of Climate Change and Sustainable Development (ICCSD). ICCSD examines two scenarios with varying levels of zero-carbon generation:

- In the Reinforced Policy Scenario, the generation mix comprises 42% wind and solar, 20% nuclear, and 12% hydro - for a total of 74% zero-carbon power. This scenario results in a total system cost of $35 per MWh, above our own estimate of $26 per MWh.
- In the 1.5°C-aligned scenario, the wind and solar share increases to 62%, with 16% nuclear and 10% hydro, for a total of 88% zero-carbon power. In this case, system costs rise to $47 per MWh, reflecting the increased system integration and flexibility requirements associated with a higher share of wind and solar.

In both scenarios, the ETC and ICCSD projections are below China's current average wholesale electricity price of $58 per MWh, indicating a clear pathway to lower-cost, zero-carbon power.

Mediterranean Climate archetype – Spain case study

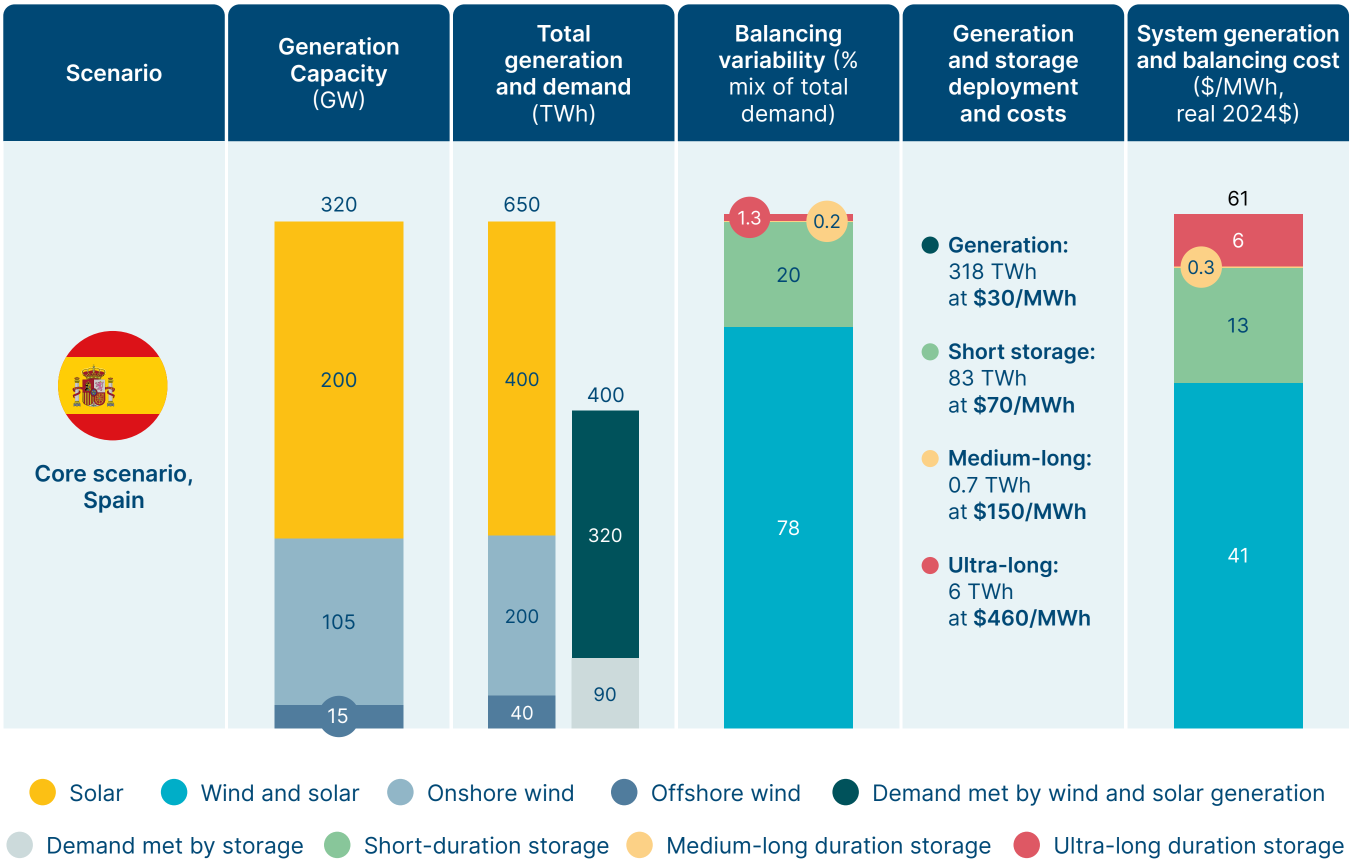
Our illustrative chart estimates for a Mediterranean Climate system, using Spain as a case study, are shown in Exhibit 1.50 System costs are higher than those in India and China, due to a greater need for short- and ultra-long duration balancing, though they remain well below historical European electricity prices.

- The generation mix is dominated by solar, which provides 62% of total generation, with onshore wind supplying 32% and a modest offshore wind contribution (6%). The system includes 320 GW of capacity, generating 649 TWh annually to meet 407 TWh of demand.
- Generation costs are estimated at $30 per MWh, reflecting Spain's excellent solar resource base. However, balancing requirements are more complex than in the low latitude archetype, with a mix of daily and seasonal variability requiring short-duration storage and limited contributions from medium- and ultra-long duration technologies.
- The total system generation cost is estimated at $61 per MWh, comprised of $41 per MWh from generation, $13 per MWh from short-duration storage, $6 per MWh from ultra-long duration storage, and $0.3 per MWh from medium-duration balancing. The medium-duration requirement is minimal in absolute terms, but highlights the value of even small volumes of flexible, multi-day storage in a solar-heavy system.

Exhibit 1.50

Total system generation costs for a 2050 system for the Mediterranean

$/MWh (real 2024$)



NOTE: Surplus generation (the difference between demand and generation) is either curtailed or used in electrolysers. Generation costs are derived based on the generation mix using BNEF 2050 mid CAPEX and OPEX estimates, alongside capacity factors from the average weather year supply scenario (representing the long-term average), 30-year project lifetimes, and real WACC of 4%, 5%, and 6% for solar, onshore wind, and offshore wind, respectively. Storage costs are derived using the LCOS methodology outlined in this report, with the input electricity cost for all storage technologies set to be the archetype's generation cost per MWh. Efficiency losses for storage technologies are included (assumed efficiencies are 90% for short, 60% for medium-long, 40% for ultra-long). Surplus generation arises from overbuild required to meet balancing needs and is included in both energy and cost calculations. Cost estimates are in 2024 $/MWh and reflect levelised costs of generation and storage, including contributions from surplus energy.

SOURCE: Systemiq analysis for the ETC; BNEF (2025), *LCOE: Data Viewer*.

Exhibit 1.51 compares our illustrative modelling for Spain with results from Aurora's dispatch model. Aurora assumes a lower wind and solar share (91% vs. our 100%) and includes some firm capacity from nuclear and gas. This reduces the storage requirement while increasing total firm capacity:

- In the Aurora Baseline scenario, total system costs are slightly lower at $53 per MWh. The generation mix includes less wind (109 GW in Aurora and 120 GW in ETC), moderate solar buildout, and a notable role for interconnection, alongside some continued gas and nuclear capacity.

Both scenarios show that a low-cost, zero-carbon power system is achievable in Spain. Estimated costs remain well below historical averages, underscoring the potential of solar-dominated systems in Southern Europe - even where some storage and seasonal balancing are still required.

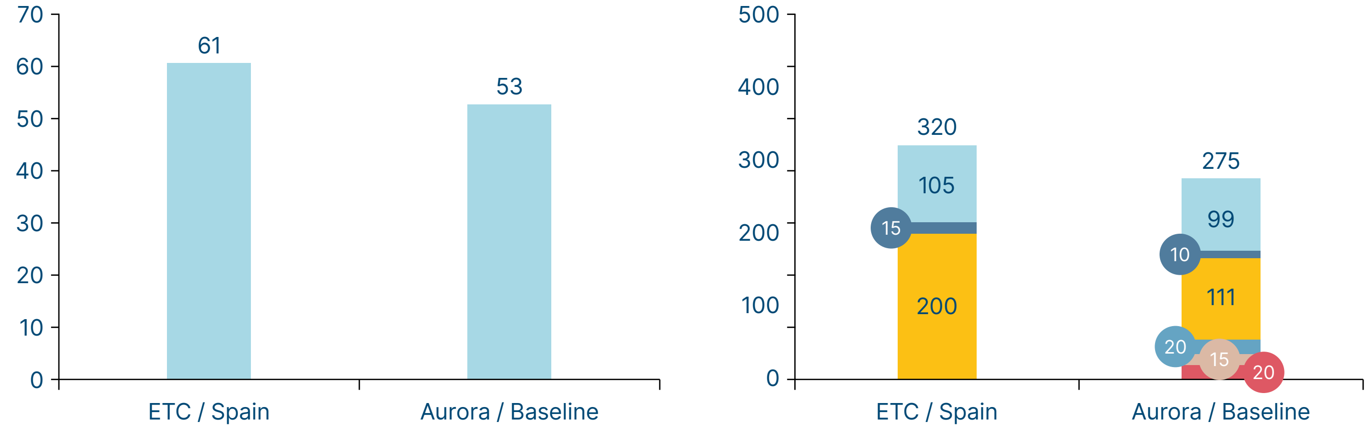
Together, these case studies highlight the diverse pathways to low-cost, zero-carbon power systems across different regional contexts – with generation mixes, balancing needs, and system costs shaped by local resources and technologies, yet all delivering electricity more affordably than today.

Exhibit 1.51

Dispatch comparison results for Spain

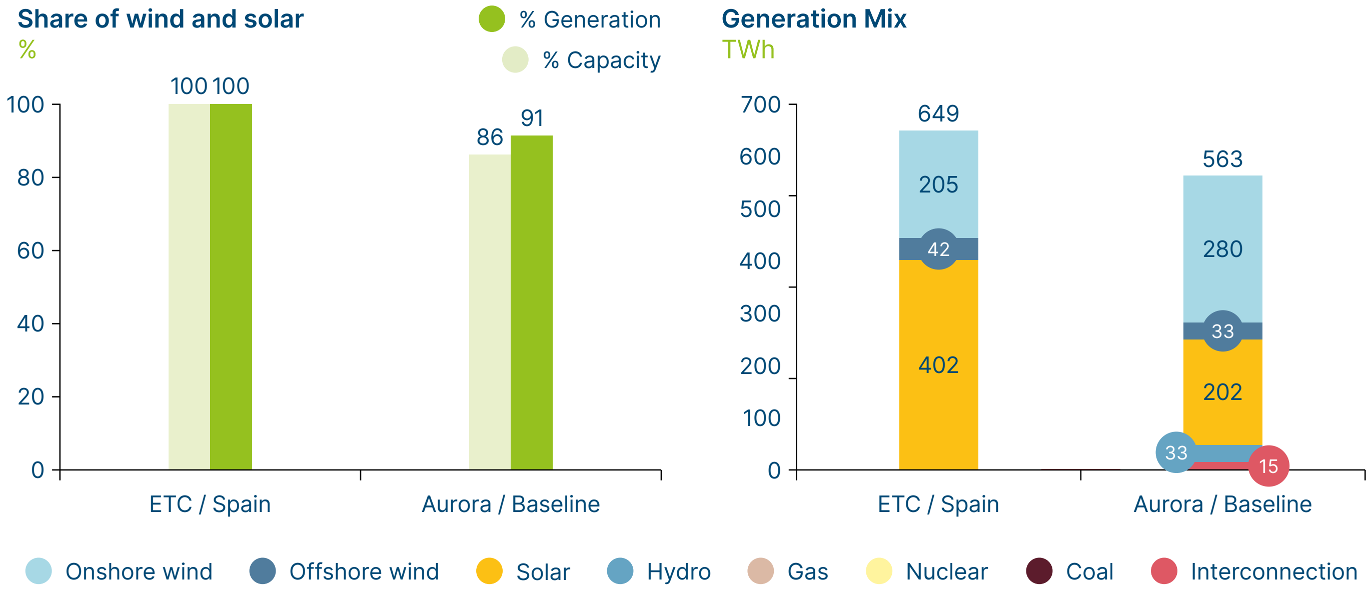
Total system generation and balancing costs
$/MWh (real 2024)

Capacity Mix
GW



Share of wind and solar
%

Generation Mix
TWh



NOTE: Other includes biomass (with and without CCS). Aurora assumes average capacity factors across wind and solar sources, of 32%, 38%, and 21% for onshore, offshore wind, and solar, respectively (higher than ETC's 22%, 32%, 23%).

SOURCE: Systemiq analysis for the ETC; Aurora (2023), *Long Duration Energy Storage in Spain.*

2 Managing grid expansion to minimise grid costs per kWh

Large increases in electricity demand will require not only a huge expansion of renewable and other low carbon generation, but also large scale expansion of both transmission and distribution grids. In our briefing note, *Building Grids Faster: The Backbone of the Energy Transition,* the ETC provided an assessment of the scale of the grid build challenge – a projection that grids will more than double in size by 2050 to enable a net-zero pathway – and laid out the critical priorities to deliver this build.[147]

This chapter covers the grid build challenge and the implications for grid costs, covering in turn:

1. **The changing nature of grid challenges as a result of changes in the pattern of both supply and demand.**
2. **The need for large scale grid investment in both distribution and transmission grids,** and the implementation challenges in achieving the required grid investment could grow from $370 billion in 2024 to around $850 billion per annum in the 2030s and 40s.[148]
3. **The opportunity to reduce costs by optimal grid design and operation.** This will entail deploying multiple IGTs and ensuring maximum DSF. These approaches could reduce required grid build by up to 35% vs. a business as usual scenario.
4. **Trends in grid costs per kWh.** Total grid costs will inevitably increase. This may initially result in small increases in grid costs per kWh, but as electricity demand increases to match the new capacity, the per kWh cost could fall by 2050 and could be significantly below current levels if opportunities for grid optimisation are seized.[149]
5. **Implementation and policy priorities**, including reform of planning and permitting systems, market designs to create incentives for optimal grid development, and actions to overcome potential supply chain constraints.

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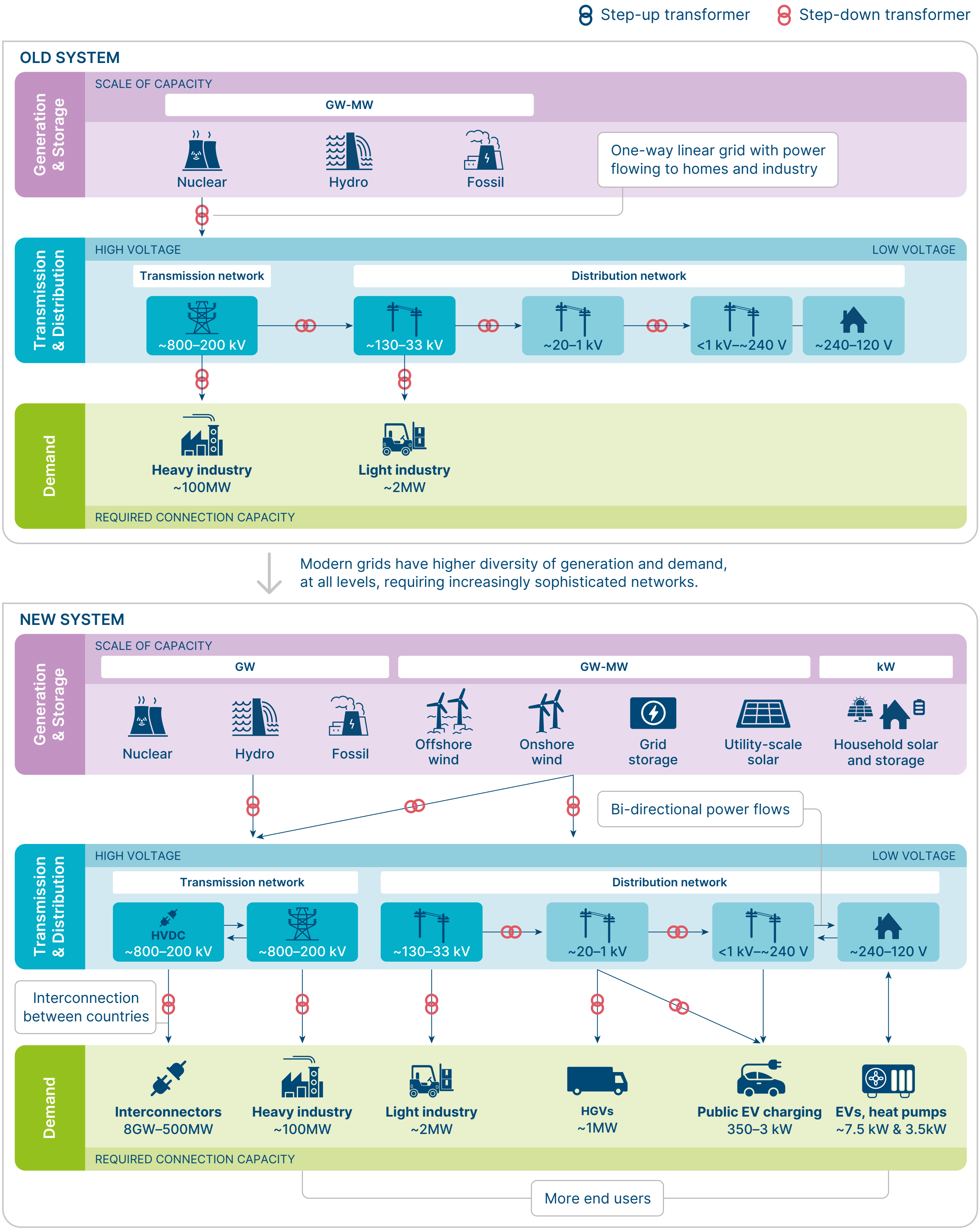
[147] ETC (2024), *Building Grids Faster: The Backbone of the Energy Transition.*

[148] Systemiq analysis for the ETC; BNEF (2024), *New Energy Outlook.*

[149] Systemiq analysis for the ETC; BNEF (2024), *New Energy Outlook.*

Exhibit 2.1

Fossil dominated systems are linear. Clean, modern grids are more complex and flexible, with increased generation options and demand requirements



One-way linear grid with power flowing to homes and industry

Modern grids have higher diversity of generation and demand, at all levels, requiring increasingly sophisticated networks.

Bi-directional power flows

Interconnection between countries

More end users

NOTE: The delineation between transmission and distribution grids is different between countries, in England and China the distribution grids operate at higher voltage levels, above and beyond 100 kV, whereas in Scotland and the United States, the maximum voltage on the distribution grid is around 35 kV.

SOURCE: Systemiq analysis for the ETC.

2.1 The changing shape of grids given new patterns of supply and demand

Power decarbonisation and wider electrification are together changing the “map“ of electricity networks by increasing the complexity of grid design and operation [Exhibit 2.1]. Four factors are particularly important:

1. **The growth of renewable power generation and the reduced role for large thermal plants**. This tends to produce a more dispersed generation system with larger number of generation assets often located further away from major demand centres.
2. **Electrification of road transport, buildings, and industry**. This leads both to increasing average and peak power supply needs at household and local distribution level and can create new locations of industrial demand to be connected to the grid.
3. **The increasing role of rooftop solar PV generation**, sometimes combined with battery capacity, which moves generation supply “behind the meter,“ potentially reducing the need for, and revenue of, distribution network companies.
4. **The development of multiple forms of storage capacity**, which could connect at different levels of the distribution and transmission grids.

These factors have implications for the pattern and scale of demand, the scale of investment and the implementation challenges faced at different network levels.

2.1.1 Changing demand at different network levels

Distribution networks represent the largest part of the power network system, accounting for 66 million km of wires globally, vs. 7 million km in the transmission network.[150] The changing demands facing distribution networks differ by network level [Exhibit 2.2].[151]

The distribution low voltage (DLV) system delivers electricity to households and small businesses. The voltage level is 100–127 V at a frequency of 60 Hz in the United States, Canada, Japan, and parts of Central and South America and 220–240 V at 50 Hz in most of Europe, Asia, Africa, and Australia.[152] At this network level, a single electrical secondary substation (of ~400 kW) capacity may serve 100 households in an urban setting (although this varies significantly across substations and regions, and rural substations serve fewer customers). Key drivers of change at this level are a greater use of a wide range of electrical appliances, increased AC as the climate warms, switches to heat pumps in colder countries, and domestic charging of EVs. Together, these changing demands will drive significant increases in both average and peak power demands. For example:

- Households in the UK currently consume 0.2–0.8 kW on average across the day, 5–10 kW at peak and 5–20 kWh per day. In the future, consumption could double, reaching 0.5–1.2 kW, 8–22 kW, and 10–30 kWh, respectively.[153]
- Households in India currently consume 0.1–0.3 kW on average 1–3 kW peak and 3–7 kWh per day. In the future, consumption could reach 0.4–0.8 kW, 5–10 kW, and 10–20 kWh, respectively.[154]

Many households and small businesses will use rooftop solar combined with battery systems in the future to cost-effectively cover a significant proportion of demand (up to 50+% during summer in UK, and close to 100% on many days in sun belt countries).[155] However, as electrification increases, some individual substations may need to be replaced at significant capital cost (e.g., $300,000 per secondary substation, of which $30,000 is for the substation itself, with the rest of the cost covering cables and other components).[156]

The distribution medium voltage (DMV) system (6.6–36 kV[157]) pools supply to multiple neighbourhoods and will also in some cases directly connect to medium scale electricity users such as supermarkets and EV charging facilities for vans, buses and trucks – use cases which are expected to grow as electrification increases. A medium voltage substation may serve 10–20 low level substations, equivalent to 1–10 MW of capacity and 1,000–5,000 households.[158]

At the distribution high voltage level (DHV) primary substations upgrade the network voltage from the DMV level to the DHV level (45 kV to 230 kV).[159] Commercial and industrial users (generally in the sub-10 MW range) often connect at this level. DHV level connections are likely to increase as a result of:

- The increasing electrification of light industry (e.g., heat generation for food processing)[160] and large scale agricultural operations, plus the growth of data centres.
- Increasing investments in grid scale batteries which may connect at this level (or at the DMV level).
- Increasing development of moderate scale commercial solar rooftop arrays and small wind farms which may also connect at either DMV or DHV levels.

The transmission level typically serves electricity supply and demand for a whole country, or large regions of a country (for example, the US has three major and two minor transmission networks, with only light interconnection between them).[161] Overall the transmission level must manage changing trends at each distribution level and provide any additional system balancing services to ensure that overall grid frequency remains in the required range (e.g., 49.5–50.5 Hz in the UK[162] and 59.7–60.3 Hz in the US).[163]

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[150] BNEF (2024), *New Energy Outlook.*

[151] While most countries use a similar tiered system, the exact terminology and voltage thresholds vary.

[152] World Population Review (2025), *Voltage by Country 2025.*

[153] Systemiq analysis for the ETC; Contemporary Structures (2023), *How Much Electricity Does a Heat Pump Use?;* NEA (2022), *Electricity Consumption Around the Home;* EVBOX (2025), EV charging stations for home or business in the UK. Available at https://evbox.com/uk-en/ev-chargers. [Accessed January 2025]; US DOE (2018), *Department of Energy Announces $19 Million for Advanced Battery and Electrification Research to Enable Extreme Fast Charging;* US DOE (2024), *Estimating Appliance and Home Electronic Energy Use.*

[154] Systemiq analysis for the ETC; TERI (2024), *India's Electricity Transition Pathways to 2050: Scenarios and Insights.*

[155] The Renewable Energy Hub (2025), *Solar Panels UK: A Guide for 2025;* Zhang, Z. et al. (2025), *Worldwide Rooftop Photovoltaic Electricity Generation May Mitigate Global Warming, Nature Climate Change.*

[156] Systemiq analysis for the ETC; National Grid (2023), *Statement Of Methodology And Charges For Connection To National Grid Electricity Distribution (South West) Plc's Electricity Distribution System.*

[157] Europacable (2014), *An Introduction to Medium and Low Voltage Cables in Distribution Networks as support of Smart Grids.*

[158] Systemiq analysis for the ETC; Regen (2024) *Electrification: The local grid challenge.*

[159] Network Power Connections (2025), *Voltages And Their Classifications.*

[160] Systemiq (2025), *A Lightning Moment For Industry.*

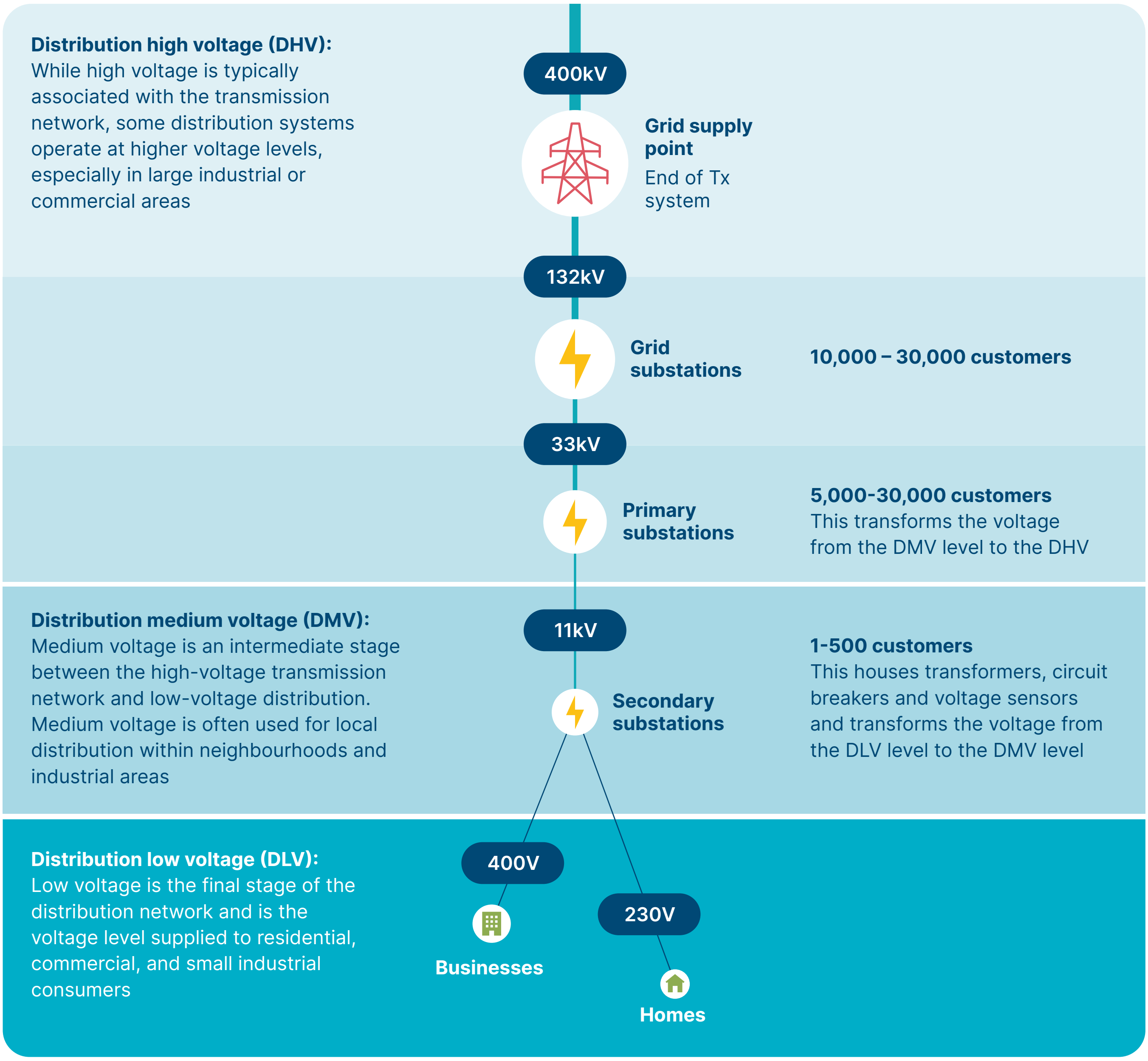
[161] North American Electric Reliability Corporation (2025), *ERO Enterprise, Regional Entities.*

[162] Mains Frequency (2017), *GB Mains Frequency.*

[163] StackExchange (2017), *In the USA, the grid transmits power at around 60Hz – how big of a frequency deviation is tolerable.* Available at https://electronics.stackexchange.com/questions/312509/in-the-usa-the-grid-transmits-power-at-around-60hz-how-big-of-a-frequency-devi. [Accessed January 2025].

Exhibit 2.2

Distribution networks are typically made up of three voltage levels, which vary by region and country, and different demand centres connect at each level



Distribution high voltage (DHV): While high voltage is typically associated with the transmission network, some distribution systems operate at higher voltage levels, especially in large industrial or commercial areas

Distribution medium voltage (DMV): Medium voltage is an intermediate stage between the high-voltage transmission network and low-voltage distribution. Medium voltage is often used for local distribution within neighbourhoods and industrial areas

Distribution low voltage (DLV): Low voltage is the final stage of the distribution network and is the voltage level supplied to residential, commercial, and small industrial consumers

10,000 – 30,000 customers

5,000-30,000 customers This transforms the voltage from the DMV level to the DHV

1-500 customers This houses transformers, circuit breakers and voltage sensors and transforms the voltage from the DLV level to the DMV level

NOTE: DLV refers to distribution low voltage. DMV refers to distribution medium voltage. DHV refers to distribution high voltage level. Tx is transmission.

SOURCE: Systemiq analysis for the ETC; Adapted from a graphic with permission from Regen (2024), *Electrification: The local grid challenge.* Available at: https://www.regen.co.uk/insights/electrification-the-local-grid-challenge.

2.2 Scale of required investment for distribution and transmission grids

To deliver the required growth in electricity and accommodate the changing nature of power generation and consumption, countries will need to significantly expand and upgrade their grids. Estimates suggest that the total global grid length must grow by 2–4 times by 2050, growing from around 73 million km of grid in 2022 to around 150–200 million km in 2050, with growth across all regions [Exhibit 2.3].[164] In countries such as India this simply represents a continuation of the pace of grid built out seen in the last decade – in Western Europe and the US, the increase will be a step change after a period of relatively slow investment.

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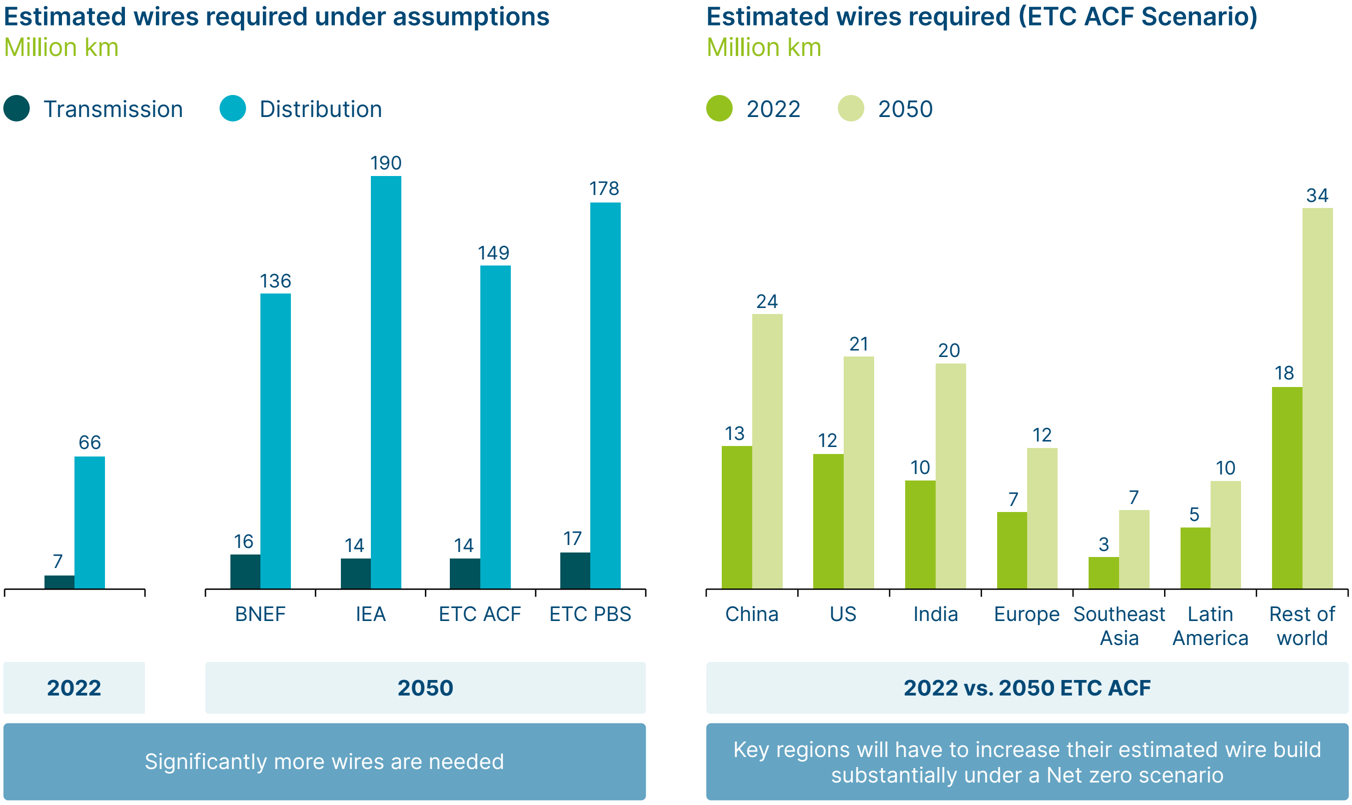
[164] Systemiq analysis for the ETC; BNEF (2024), *New Energy Outlook.*

Exhibit 2.3

Transmission and distribution networks will need to significantly increase across all regions



Estimated wires required under assumptions
Million km

Estimated wires required (ETC ACF Scenario)
Million km

Significantly more wires are needed

Key regions will have to increase their estimated wire build substantially under a Net zero scenario

NOTE: BNEF data used represents NZS (Net-Zero Scenario). The Accelerated but Clearly Feasible (ACF) scenario is clearly technically and economically feasible, but in some sectors will require more forceful policy support than currently in place. We have included 50% of hydrogen demand in these estimates. The Possible But Stretching scenario (PBS) Scenario is also technically and economically feasible but would require significant strengthening of current commitments and policies.

SOURCE: BNEF (2023), *NEO grids;* BNEF (2023), *NEO data viewer;* IEA (2023), *Electricity Grids and Secure Energy Transitions.*

Both transmission and distribution grids will need to more than double in length. BNEF estimates the average costs per km for grid investments out to 2050 to be $1–2.5 million per km transmission and $0.2-0.3 million per km for distribution. Costs per km for the high voltage and power capacity transmission lines (plus related equipment) are thus on average around 7 times higher than for distribution networks (taking the midpoints of each range),[165] but distribution networks are still likely to account for around 55% of all investment [Exhibit 2.4]. [166]

In certain low-income countries, some national grids have not been growing at all. Around 600 million people in Sub-Saharan Africa live without access to electricity, and where connections to the national grid are in place, supply is often variable and unreliable. In these instances expanding the prevalence of mini-grids (a set of small-scale electricity generators connected to a local distribution network) may be an important step before national grids can become widespread.[167]

In addition to extending networks to connect new sources of supply and demand, investments will also need to cover the maintenance of existing assets [Exhibit 2.4]:

- **Replacing ageing assets to maintain the existing asset base**: The need for reinvestment can be partially reduced through greater grid digitalisation, particularly asset health monitoring systems that use a wide range of data inputs to detect early signs of degradation. However, the potential to meaningfully extend the lifetime of large, critical infrastructure remains limited, due to safety risks and the consequences of unexpected failure. Significant replacement investments will therefore be required, primarily in developed economies, where grid infrastructure is older on average.

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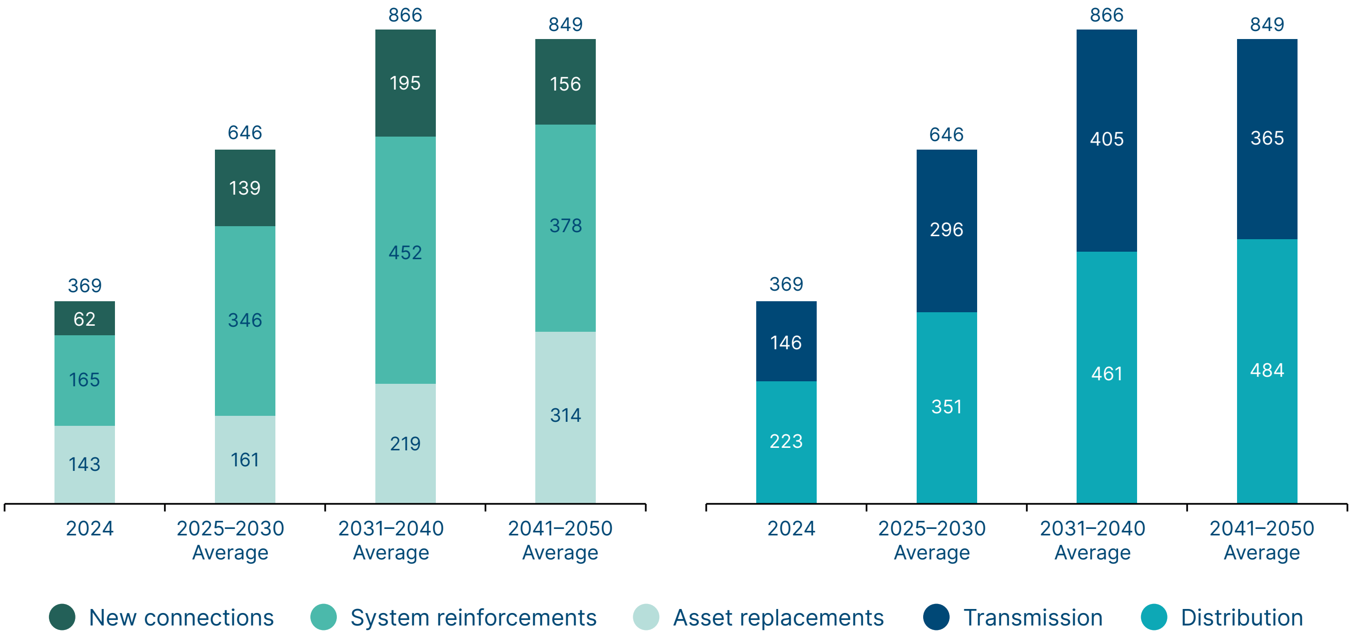
[165] Global average grid costs per km estimate based on BNEF (2024), *New Energy Outlook 2024 Grids.*

[166] Deploying new distribution network infrastructure (including substations and circuits) is generally easier than transmission infrastructure due to the lower voltage levels, simpler cable protection schemes, and generally lower regulatory and planning barriers. See NESO (2024) *Clean Power 2030.*

[167] CAMCO (2024), *Opportunities and risks in the African grid of the future.*

Exhibit 2.4

A significant increase in global grid investments is required across new connections, asset replacements, and system reinforcements to achieve net-zero by 2050



Breakdown of global annual grid investment by grid category, based on BNEF's Net-Zero Scenario (2024–2050)
$bn

Breakdown of global annual grid investment by transmission and distribution, based on BNEF's Net-Zero Scenario (2024–2050)
$bn

SOURCE: Systemiq analysis for the ETC; BNEF (2024), *NEO grids*.

- **System reinforcements**: These include investments to increase the capacity of existing power lines as well as changes to existing grid infrastructure to enable new connections (across supply and demand) and higher complexity and flexibility in grids (e.g., enabling bi-directional power flows in distribution networks) as well as grid management optimisation/digitalisation (e.g., installing sensors and software for managing higher complexity power flows).

2.2.1 Implementation challenges at different network levels

Delivering the scale of investment needed will be a major implementation challenge at both the transmission and distribution level.

At the transmission level, the average global annual buildout required is 0.25–0.36 million km per year through to 2050,[168] a scale of development that has never been achieved before. Achieving this will require not only physical resources but also substantial institutional capacity to coordinate, approve, and deliver projects at pace. The main challenges around achieving this transmission buildout include:

- **Permitting delays** faced by transmission projects, especially in advanced economies where the development of transmission lines often takes up to 8 years (compared to 1.5 and 3 years in China and India, respectively). These delays in part reflect local opposition to visually intrusive new pylon line developments.[169]
- **Supply chain constraints**, e.g., lead times for key components such as cables and transformers have nearly doubled in recent years, with record-high backlogs and procurement delays now common.
- **Rising prices for cables and transformers** due to high demand, inflation, and increased costs of critical materials such as copper, aluminium, and steel.
- **Skilled workforce shortages**, with an estimated 1.5 million job gap in the power grid sector by 2030.[167]

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[168] IEA (2025), *Building the Future Transmission Grid.*

[169] ETC (2024), *Building grids faster: the backbone of the energy transition;* IEA (2025), *Building the Future Transmission Grid.*

- **Financial constraints and utility solvency issues in developing economies** are a major barrier to grid investment. Grid projects are typically led by state-owned utilities which in many developing economies lack access to project finance and must rely on corporate borrowing, which often requires sovereign guarantees that fiscally constrained governments cannot provide. This creates a vicious cycle in some regions, particularly Sub-Saharan Africa, where weak utility balance sheets prevent investment in grid infrastructure, limiting the integration of new generation capacity and compounding reliability issues.[170,171]

At the distribution level, the average global annual buildout required will be 2.5–4 million km per year.[172] In many countries, this new grid build extension will be easier to achieve than system reinforcements, which face challenges including:

- The sheer **number and complexity** of the upgrades required, many of which will require digging up streets.
- **Regulatory regimes** which, in some cases, make it difficult to invest ahead of need rather than in response to rising demands.
- **Imperfect information** relating to existing assets as a result of past ad hoc approaches to system reinforcement and inadequate record keeping**.** As a result, distribution companies often do not know how much spare capacity there is at different levels of the network and may invest in more new assets than what is needed to meet demand. Analysis by Vivid Economics and Imperial College London showed that, in the UK, in a scenario where actual available existing grid capacity is higher than currently assumed, required additional cable length could be reduced by over 40%.[173]
- Most traditional distribution network substations are designed for **unidirectional power flow** – from higher-voltage transmission systems down to consumers. However, the integration of distributed energy resources, such as rooftop solar panels, wind turbines, and battery storage systems, has introduced the need for bidirectional power flow in distribution networks. This has created challenges around voltage regulation and fault protection.

In emerging markets, these challenges are often again compounded by the limited financial solvency of utilities, which are typically responsible for grid investment but may be unable to access capital without sovereign guarantees, constrained by national fiscal capacity. This creates a systemic barrier to investment in both networks and new generation capacity.

2.3 Optimisation to reduce grid investment needs

Grids are a fundamental enabler of electrification and clean electricity development and will require substantial expansion over the next decade. However, this expansion must be achieved cost-effectively. Optimisation strategies can significantly reduce grid investment needs by improving system efficiency and leveraging technologies that minimise the need for new infrastructure.

One key priority is strategic power system planning, including decisions about the balance between wind and solar, clean firm generation, storage, and any continued fossil fuel use. Planning a well-integrated and diversified system can reduce grid build-out requirements by avoiding congestion, enabling co-location of resources, and supporting more stable and efficient power flows.

In addition there are three main opportunities to reduce grid investment needs:

- DSF to reduce the peak electricity demands which determine required grid capacity at different levels in the network. ETC analysis identifies that this could cut required distribution system investment by up to 40% percent. Market designs which support time of day pricing are a key enabler.
- Deployment of IGTs which can significantly increase the efficiency with which grid assets are used. These could, in principle, reduce required grid investment needs by as much as 35%.[174] Changes in grid company regulation may be required to create strong market incentives for their deployment.
- Optimal location of generation and storage assets, and of major new demand centres, including the use of existing grid connections and the optimal use of international interconnectors. Maximising this potential will require market designs which create incentives for optimal location.

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[170] EBRD (2023), *Power Sector Reform: Unlocking Investment in Grid Infrastructure in Emerging Markets*.

[171] IEA (2023), *Electricity Grids and Secure Energy Transitions in Africa*.

[172] Systemiq analysis for the ETC; BNEF (2023), *New Energy Outlook*; IEA (2023), *Electricity Grids and Secure Energy Transitions*; IEA (2023), *Electricity Grids and Secure Energy Transitions*.

[173] Vivid Economics, Imperial College London (2019), *Accelerated electrification and the GB electricity system*. See "High Headroom" scenario.

[174] Systemiq analysis for the ETC; CurrENT (2024), *Prospects for innovative power grid technologies*.

2.3.1 Demand side flexibility – a major opportunity to reduce distribution network investment

The potential for demand side flexibility to help balance electricity supply and demand was discussed in Section 1.4. By shifting demand away from peak demand periods, DSF can reduce the need to invest in the various forms of short duration storage which would otherwise be required to achieve balance. DSF can also play an important role in reducing the need for new distribution network investment since network capacity requirements are driven by peak electricity demands.

Peak demands in electricity systems are already significantly higher than average demands across the day [Exhibit 2.5] but the peak to average ratio could increase still further as a result of wider electrification.

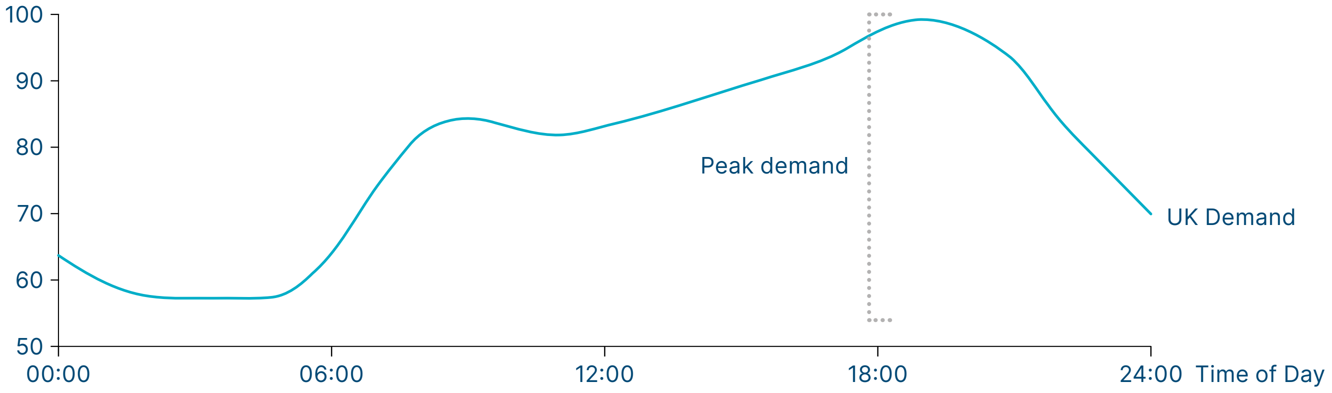
- In the UK, the electrification of road transport (with significant vehicle charging at household level) and of residential heating could drive an increase in the typical household's daily winter peak demand from 8 kW to 22 kW, but optimal adoption of DSF could reduce this to 13 kW [Exhibit 2.6].
- In India, rising demand for AC and other electric appliances could drive an increase in typical summer daily peak demand from 1.5 kW to 8 kW, but the optimal deployment of DSF could reduce this to 5 kW.[175]

Exhibit 2.5

Substations and distribution networks are sized based on peak power demand

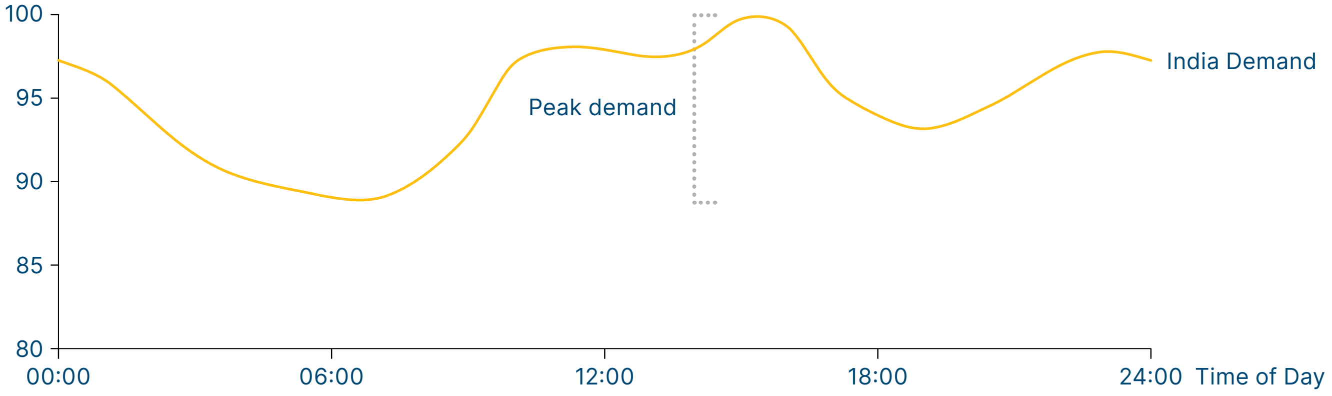
Illustrative 2024 UK winter peak power demand (national level)

UK winter peak demand (% of peak)



Illustrative 2024 India summer peak power demand (national level)

India summer peak demand (% of peak)



NOTE: National demand data has been normalised relative to the peak daily demand. In the UK, annual residential power demand peaks generally occur during winter, driven by heating demand, and hourly peaks during the evening (and morning to some extent). In India, annual peaks generally occur during summer, driven by air cooling demand, and hourly peaks during the afternoon.

SOURCE: Energy Dashboard (2024), *Historical*. Available at https://www.energydashboard.co.uk/historical. [Accessed January 2025] ; IEA (2024), *Real-Time Electricity Tracker*. Available at https://www.iea.org/data-and-statistics/data-tools/real-time-electricity-tracker. [Accessed January 2025].

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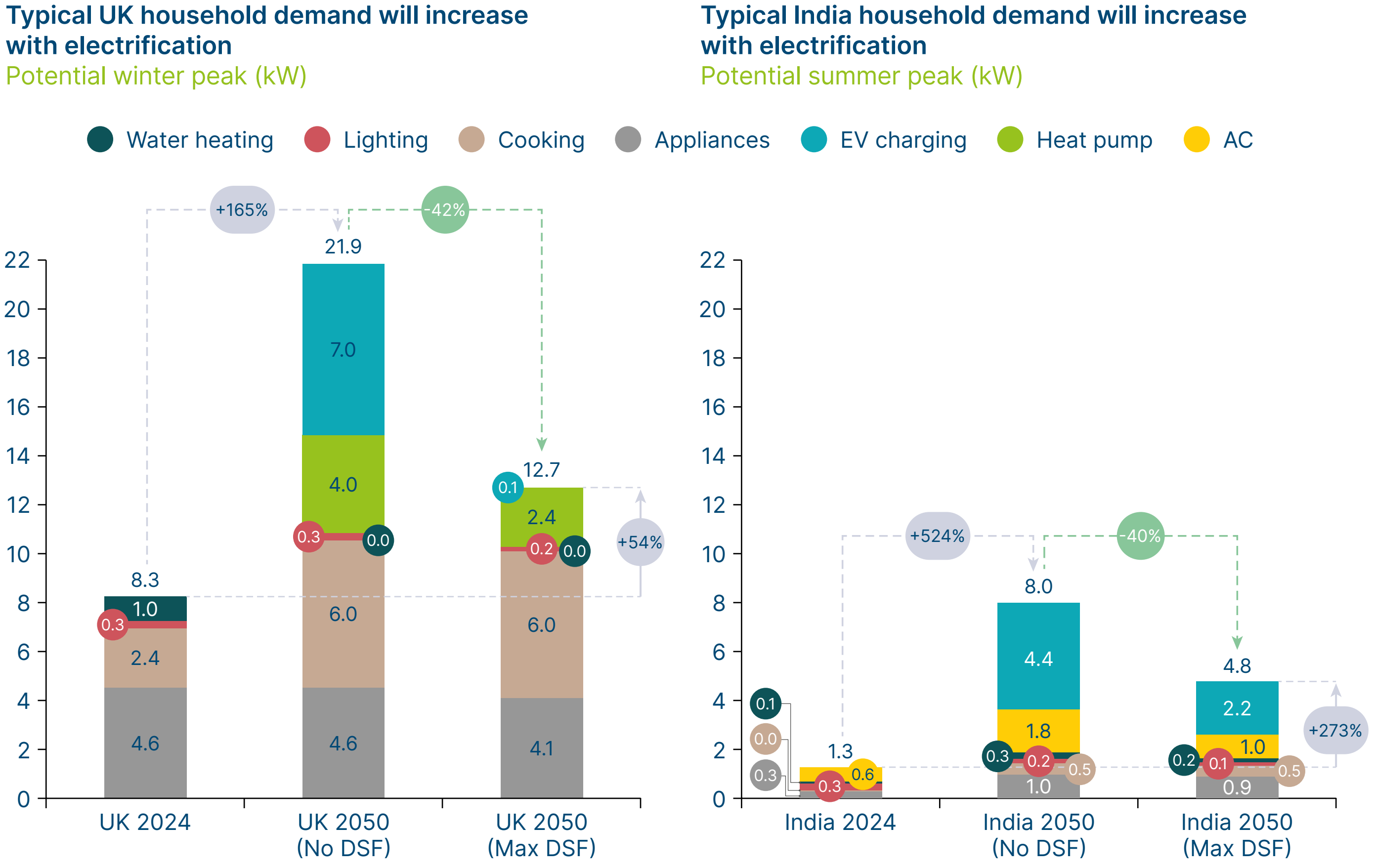
[175] TERI (2024), *India's Electricity Transition Pathways to 2050: Scenarios and Insights*.

Exhibit 2.6

Increases in household-level peak power demand are expected, however Demand Side Flexibility can offset some peak demand increase



Typical UK household demand will increase with electrification

Potential winter peak (kW)

Typical India household demand will increase with electrification

Potential summer peak (kW)

Driven by the electrification of:

- Household heating: Heat pumps draw approximately 4 kW of flexible demand.
- Personal vehicles: EV charging could contribute around 7 kW of flexible demand.

Driven by increased appliance penetration and electrification:

- AC: AC units draw around 3 kW of flexible demand
- Personal vehicles: EV charging could contribute around 4 kW of flexible demand (accounting for high proportion of three-and-two-wheelers).

NOTE: Indian data accounts for the penetration of appliances throughout the population, therefore these are averaged values which don't directly correlate with appliance consumptions.

SOURCE: Systemiq analysis for the ETC; TERI (2024), *India's Electricity Transition Pathways to 2050;* US Department of Energy (2018), *Department of Energy Announces $19 Million for Advanced Battery and Electrification Research to Enable Extreme Fast Charging;* Contemporary Structures (2023), *How Much Electricity Does a Heat Pump Use?*

Alongside network upgrade requirements, driven by peak demand, fuses in buildings will need upgrading in line with the capacity increase (e.g., from 60 A[176] to 100 A for a house going from a peak demand of 8 kW to 20 kW).[177] Achieving the potential reductions in individual household peaks outlined above would reduce the need for increased network investment at the individual household level, in the low-voltage network and at secondary substations.[178]

At the level of medium voltage networks and primary substations, increases in demand could be even higher due to the connection of commercial and industrial demand sources which connect at this level. However, the impact of residential peak demand is somewhat reduced by an averaging effect at higher voltage levels, with peak demand in different households and locations being partially offset. At DHV and transmission grid levels, the impact of peak demand is also reduced by an averaging effect. But demand side flexibility could still have a material impact on total required network investment at these levels.

[176] A stands for ampere which is the unit for electric currents.

[177] This analysis simplifies the significant variations across demand zones (in terms of numbers of customers, demand diversity patterns, and peak demand timing) to develop illustrative examples of the future impacts on distribution networks.

[178] Local distribution networks are designed to cater for peak loads, considering "After Diversity Maximum Demand" (ADMD), which is used to determine the required size of the distribution network, accounting for demand diversity effects (i.e. people using appliances at different times) to determine the aggregated peak demand patterns for a demand zone. This reduces the average per-household peak demand by up to around 70% (relative to an individual household peak demand).

Another potential impact is increasing utilisation and decreasing redundancy in networks. The general reliability standard used in electricity networks is the "N-1 criterion," which means that the system must be able to continue operating without exceeding operational limits despite the failure of one critical component (transmission line, transformer, or generator). DSF could decrease the redundancy required to a more economically optimal range (e.g., N-0.5 to N-0.75) by increasing the headroom in the system, enabling security of supply with fewer components.[179]

The impact of DSF on household peak demand from the grid, can be achieved by shifting consumer demands (e.g., the timing of EV charging, heating, or AC system use) away from peak periods. It can also be achieved by installing rooftop solar PV if demand naturally aligns with solar production or can be shifted to align, or if batteries are installed at building level. Box F describes developments in Australia and Pakistan, where large scale deployment of rooftop solar promises to significantly reduce local distribution network requirements (as well as peak generation needs) aided by time of day pricing for both import from and export to the grid.

Seizing the very large potential for DSF to reduce distribution network costs will require:

- Accelerating smart metre rollout.
- Implementing time-of-use tariffs, dynamic network tariffs, and wholesale price signals to incentivise behavioural demand response.
- Establishing clear rules on data usage, exchange and interoperability standards.
- Reducing barriers to entry via financing through financial institutions and government-backed grants.
- Incentivising automated demand response across key demand side technologies (including EVs, heat pumps, and other home appliances).[180]

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179 National Infrastructure Commission (2025), *Electricity distribution networks: Creating capacity for the future.*

180 ETC (2025), *Demand side flexibility – unleashing untapped potential for clean power.*

Box F

Rooftop solar impact in Australia and Pakistan

Australia's rapid adoption of rooftop solar power is fundamentally transforming its electricity system. Once designed for one-way energy flow from large coal-fired plants, the National Electricity Market (NEM) now faces significant challenges from the two-way electricity flows caused by widespread rooftop solar installations. Rooftop solar totalled 25 GW of capacity in Australia in 2024 (~25% of 96 GW total), generating 11% of Australia's total electricity in the first half of the year.[181] Approximately one-third of Australian homes now have rooftop solar,[182] with some states like Queensland and South Australia seeing penetration rates over 50%. This rapid uptake means rooftop solar at times provides more than half of total electricity demand across the NEM, and even up to 70% in Western Australia's separate Wholesale Electricity Market.[183]

This transformation presents operational challenges, particularly around "minimum system demand" periods, when solar production exceeds local energy consumption, creating reverse energy flows back into the grid. In South Australia, rooftop solar penetration is so high that on mild sunny days, it not only meets all local electricity demand but also exports surplus electricity to neighbouring regions. Consequently, Australia's energy system operators face critical security risks, including voltage instability, and overloaded distribution networks.

Responding to these issues, Australia has implemented emergency backstop mechanisms, enabling grid operators to temporarily curtail rooftop solar production to maintain grid stability. Concurrently, innovative market designs such as dynamic operating envelopes (DOEs) which set flexible, real-time export limits for rooftop solar based on local grid capacity, community battery storage programmes, and dynamic pricing incentives encourage more efficient energy use and storage solutions. These interventions aim to maximise the benefits of rooftop solar while managing its impact on grid stability and reliability.

Australian consumers, suppliers, and grid operators are increasingly targeting opportunities arising from zero-cost midday electricity, leveraging dynamic tariffs and incentives to shift consumption into surplus solar periods. Although integrated solar-plus-battery systems can now deliver power at costs below conventional generation, transmission and distribution network charges, applied at every voltage tier, from 132 kV bulk-transmission through sub-transmission and 11 kV feeders to low-voltage circuits (<1 kV), continue to erode consumer savings.[184] To overcome these hurdles, Ausgrid is piloting dynamic time-of-use tariffs (currently adopted by 21% of consumers) alongside incentives for EV charging and pool heating during midday solar peaks.[185]

Ausgrid's community battery initiative, comprising six 400 kWh installations across Bondi Beach, Narara, and Cammeray, is evaluating how local energy storage can defer costly network upgrades while enabling value-sharing frameworks.[186] Through such programmes, households can engage in daily arbitrage of up to 4 kWh between midday and evening rates, unlocking reduced network charges and new revenue streams that further accelerate the uptake of distributed solar assets.[187]

Pakistan's rooftop solar market is at a more nascent stage but is experiencing rapid growth driven by frequent power outages, high electricity prices, and declining costs of solar installations. The Pakistani government has actively encouraged solar adoption through initiatives such as net-metering policies,[188] allowing consumers to offset their electricity bills by feeding surplus solar energy back into the grid. As a result, Pakistan's grid-connected, net-metered rooftop solar capacity reached about 4.1 GW by December 2024 (up from 1.3 GW in June 2023), however these metered statistics are likely an underestimate as Pakistan imported 13 GW of solar modules from China in 2024.[189]

Rooftop solar in Pakistan is already alleviating pressure on the strained national grid, especially during peak summer demand. Additionally, solar adoption is empowering communities and small businesses by reducing

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[181] Clean Energy Council (2024), *Rooftop solar and storage report.*

[182] The Guardian (2023), *Go hard and go big': How Australia got solar panels onto one in every three houses.* Available at https://www.theguardian.com/environment/2023/nov/01/how-generous-subsidies-helped-australia-to-become-a-leader-in-solar-power#:~:text=Roughly%20one%20in%20three%20Australian,on%20a%20per%20capita%20basis. [Accessed January 2025].

[183] Australian Government (2025), *Small-scale installation postcode data.*

[184] Ausgrid (2022), *Network Tariff Review.*

[185] Energy Consumers Australia (2024), *Consumer Energy Report Card.*

[186] Ausgrid (2024), *Community Battery Pilot.*

[187] ACCC (2024), *Inquiry into the National Electricity Market.*

[188] IEEFA (2024), *Optimizing solar incentives and grid infrastructure in Pakistan can benefit power distribution companies and energy consumers.*

[189] Bloomberg (2024), *Pakistan Sees Solar Boom as Chinese Imports Surge.* Available at https://www.bloomberg.com/news/articles/2024-08-09/pakistan-sees-solar-boom-as-chinese-imports-surge-bnef-says?embedded-checkout=true. [Accessed February 2025].

energy costs and enhancing energy security. However, Pakistan faces its own challenges, such as the need for substantial grid upgrades to accommodate increasing levels of distributed solar generation and issues around the financial sustainability of net-metering schemes amid rising adoption rates, with power distribution companies facing revenue shortfalls due to some demand for grid electricity being offset by self-consumption, leading to higher tariffs for some non-rooftop solar users.

Overall, both countries illustrate the profound changes rooftop solar can induce in national electricity systems, highlighting the importance of forward-looking grid management strategies, including maximising deployment of DSF solutions, residential and grid-scale batteries to fully harness the benefits of distributed renewable energy.

2.3.2 Innovative Grid Technologies to reduce network investment needs

Exhibit 2.7 and Exhibit 2.8 describe eight high potential innovative grid technologies (IGTs) which could significantly reduce required grid investments. They include:

- Hardware-based IGTs which expand firm line capacity via changes to pylons and wires.
- Software-based IGTs which optimise wires and networks to improve system visibility, decision-making, and performance.
- Flexibility management software solutions, including digital twins, which are cross-cutting and can be applied alongside all IGT options assessed.

Some of these IGTs are specifically designed for either the transmission or distribution network, and some can be implemented in both:

- Advanced conductors are primarily designed for high voltage overhead transmission lines.
- IGTs which can be implemented across transmission and distribution networks include Dynamic Line Rating (DLR), Flexible AC Transmission Systems (FACTS), and Storage as Transmission Asset (SATA).

Potential benefits, technological readiness and costs vary by IGT [Exhibit 2.9].

- Advanced conductors could potentially double the power capacity which can be carried by lines of pylons, have a Technology Readiness Level (TRL) of 9 and at an estimated cost of $50,000–200,000 per km (in terms of conductor length, rather than full transmission line costs) will be cost-effective in many situations.[190]
- Super conducting materials could potentially increase line capacity by 4 to 10 times, but are at a much earlier stage of TRL, and will be more expensive even when deployed on a large scale.[190]
- Various software based enhancements to grid operation – such as grid inertia measurement, FACTS and DLR could each potentially increase network capacity by around 30%. These technologies have high TRLs and far lower costs than the hardware based solutions. DLR has been deployed in several countries, for example, LineVision's deployment in the UK and US.[191] Its effectiveness is particularly high in temperate regions, where cooler ambient temperatures and higher wind speeds during peak demand periods enhance conductor cooling and line capacity. In contrast, DLR may offer more limited benefits in hot climates where peak loads coincide with low wind and high temperatures.[192]

The applicability of these IGTs will vary by specific circumstance and needs to be assessed in detail for each national network. Several studies suggest significant potential benefits:

- In Europe, a study by CurrENT found that implementing IGTs could feasibly unlock a 20–40% capacity improvement of the European network by 2040.[193] Taking a more conservative view of a 10–20% grid capacity increase, deployment of these technologies could equate to gaining the equivalent of 4–8 years of new grid build.[194]
- The US Department of Energy also estimates that deploying existing advanced grid technologies could increase US grid capacity by 20–100 GW and defer $5–35 billion in transmission and distribution costs over the next five years.[195]

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[190] Systemiq analysis for the ETC; CurrENT (2024), *Prospects for Innovative Power Grid Technologies;* BNEF (2023), *New Energy Outlook Grids.*

[191] National Grid (2022), *National Grid trials new technology which allows more renewable power to flow through existing power lines.*

[192] US DOE (2017), *Improving Efficiency with Dynamic Line Ratings.*

[193] CurrENT (2024), *Prospects for Innovative Power Grid Technologies.*

[194] CurrENT (2024), *Prospects for Innovative Power Grid Technologies.*

[195] US DOE (2024), *Pathways to Commercial Liftoff: Innovative Grid Deployment.*

Exhibit 2.7

IGTs Technology Overview – Hardware Solutions

Innovative grid technology overview and indicative techno-economic parameters

IGT	Category	Overview	Key advantages	TRL[A]	Network capacity increase (% of line capacity)	Indicative Cost	Scalability
Advanced Conductors	Hardware	• **Improved versions of traditional metal conductors, reinforced with composite materials resulting in a lighter, stronger and thermally stable composite core.** • Increases the efficiency, capacity, and reliability of power lines enabling higher capacities per line and reduced sag and losses. • 20,000 km of advanced conductors are installed in Europe and 175,000 km worldwide (11 kV–1,100 kV).	Up to 100% network capacity increase with costs per km on the same order of magnitude as conventional conductors. They can double the maximum current of a line and cut line losses by 25–50%, compared to conventional lines.	9	100–300%	50,000–200,000 $/km	Medium
Superconductors	Hardware	• **Eliminate electrical resistance, allowing for zero resistive losses during transmission.** • Have significantly higher power density than conventional technologies, potentially enabling lower voltage operation while maintaining high power transfer. • Requires cryogenic cooling (around -200°C for high-temperature superconductors) and specialised materials. • TRL 7 in the distribution network as superconductors have been deployed in the distribution network through 15 projects around the world. • TRL 5 in the transmission network as prototype validation is expected by 2025 via Supernode's technology, with commercial availability expected by around 2030.	400–1000% network capacity increase but with a significantly higher cost per km than conventional conductors.	7 at Dx 5 at Tx	400–1000%	Demo scale: 10–15 m $/km Commercial scale: 1–2 m $/km	Low
Voltage Upgrade	Hardware	• **Increasing the voltage of power cables reduces losses, enabling higher power transfer, improving stability, and optimising infrastructure use along existing lines.** • Larger pylons are generally required to upgrade the voltage (unless this is paired with IGTs such as advanced conductors or superconductors), which can result in permitting constraints. • TRL 9 as voltage upgrades are often deployed by transmission system operators (TSO), for example National Grid's £35 billion transmission upgrade plan from 2026–2031.	400+% capacity increase (depending on the voltage difference), allowing for more electricity transfer per line, using conventional technology.	9	30–400+%[B]	20,000–40,000 $/km	Medium
Storage as Transmission Asset (SATA)	Hardware	• Avoids congestion and curtailment during periods of excess generation, via active congestion relief (providing congestion relief by shifting load to periods with low congestion) and passive congestion relief (enhances the reliability of the network by protecting against outages). • Can operate in both passive and active congestion relief modes, both of which can reduce the need for costly transmission reinforcements while maintaining system reliability. • TRL 9 as passive congestion relief has been deployed significantly via grid boosters. While deployment of active congestion relief is lower, this has also been implemented in several grids around the world, including Germany and the US.	40% network capacity increase and improved network resilience against contingency events.	9	40%	30-125 $/MWh (battery asset cost)	High

NOTE: (A) Assumed TRL scale: TRL 1–3 = Research to Proof of Concept; TRL 4–6 = Lab to Pilot Demonstration; TRL 7–9 = Prototype demonstration to full commercial deployment. (B) Capacity increase depends on the voltage upgrade.

SOURCE: Systemiq analysis for the ETC; CurrENT (2024), *Prospects for innovative power grid technologies*; BNEF (2023), *New Energy Outlook Grids*; New Civil Engineer (2024), *National Grid publishes plan to invest £35bn in UK transmission from 2026 to 2031.*

Exhibit 2.8

IGTs Technology Overview – Software Solutions

Innovative grid technology overview and indicative techno-economic parameters

IGT	Category	Overview	Key advantages	TRL[A]	Network capacity increase (% of line capacity)[B]	Indicative Cost	Scalability
Grid Inertia Measurements	Software	• Generate live and accurate grid inertia data through frequency modulation, improving the understanding of inertia and stability limits in the system. • Inertia on the grid decreases with more renewables in the system, which may cause stability issues and curtailment. Precise inertia measurement in real-time enables targeted inertia procurements and minimises curtailment. • TRL 9 as implemented in several countries, including the UK, Australia, and Japan.	Grid inertia measurements increase network capacity by around 30% with a relatively low cost of implementation.	9	30%[C]	<10,000 $/km	High
Flexible AC Transmission Systems (FACTS)	Software	• Include Advanced Power Flow Control, Static VAR Compensators (SVCs), and Static Synchronous Compensators (STATCOMs). • Enable dynamic controlling of power flows on the grid, boosting transmission efficiency and network resilience. • By reducing congestion and balancing power flows, enable better integration of renewables and delay the need for costly grid expansions. • TRL 9 – deployed in several countries, including the UK, US, Australia and Colombia.	FACTS increases network capacity by around 30% with a relatively low cost of implementation.	9	30%	<10,000 $/km	Medium
Dynamic Line Rating (DLR)	Hardware & Software	• Use sensors and weather data to monitor weather and environmental conditions that impact the line's ability to dissipate heat and dynamically adjust the line's power transfer capability accordingly. • Improves network efficiency by giving system operators better visibility and understanding of actual line limits, enabling them to respond to real-time temperature and sag of power lines. Consequently, DLR implementation causes a variable impact on network capacity, depending on real-time external conditions. • TRL 9 as DLR has been deployed in several countries, including the UK, US, Belgium, France, and Norway.	DLR increases a line's capacity by 10–45% with a relatively low cost of implementation and enhance grid condition visibility and operation.	9	30%[D]	10,000-50,000 $/km	High
Flexibility management software	Software	• Virtual models, including digital twins, that integrate network data and external factors (including weather, topography, generation) to simulate real-time and future grid conditions, with minimal input from physical sensors. • Typically use artificial intelligence (AI) to monitor the grid using data from existing sensors and meters and extrapolate/interpolate this data to areas lacking sensors. Supports network operators in flexibility services procurement and congestion management. • TRL 9 as digital twins have been deployed in several countries.	Digital twins increase improve network operation and maintenance with a relatively low cost of implementation.	9	-	-	High

NOTE: (A) Assumed TRL scale: TRL 1–3 = Research to Proof of Concept; TRL 4–6 = Lab to Pilot Demonstration; TRL 7–9 = Prototype Demonstration to Full Commercial Deployment. (B) Capacity increase depends on the voltage upgrade. (C) Reduction in renewables output due to 30% higher inertia compared to conventional lines. (D) Depending on external conditions.

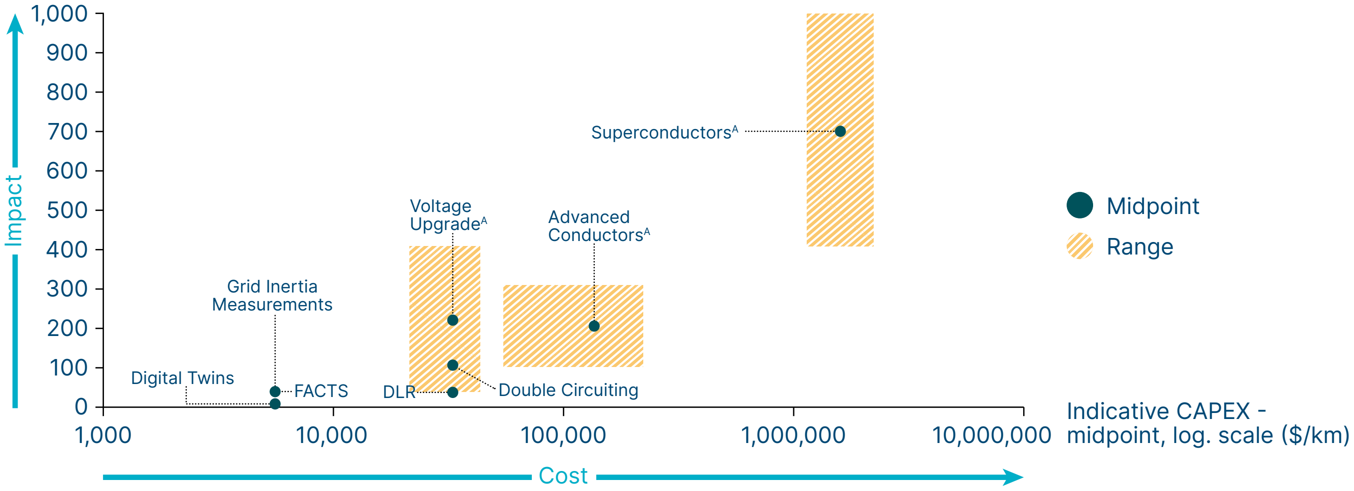
SOURCE: Systemiq analysis for the ETC; CurrENT (2024), *Prospects for innovative power grid technologies;* Quanta Technology (2023), *Storage as Transmission Asset Market Study*; Energies (2025), *Energy Storage as a Transmission Asset—Assessing the Multiple Uses of a Utility-Scale Battery Energy Storage System in Brazil.*

Exhibit 2.9

The costs of Innovative Grid Technology deployment and network impacts range significantly across the technologies assessed

Innovative Grid Technologies indicative CAPEX and network improvement estimates

Indicative network capacity increase (% of line capacity)



NOTE: (A) Denotes technologies with corresponding % and $/km ranges. The relative capacity improvement depends on the grid baseline level – grids with predominately ageing technology will see higher impacts than grids with more modern technology. The mid-points of the estimated cost and network impact ranges have been used for this comparison. DLR network capacity increase depends on external conditions.

SOURCE: Systemiq analysis for the ETC; CurrENT (2024), *Prospects for innovative power grid technologies.*

In addition to significantly reducing the need for grid investment and the resulting network costs faced by household and business consumers, IGTs could also help reduce connection queues for new locations of generation supply and large industrial/commercial demand.

They could also reduce social opposition to necessary grid build, and as a result reduce barriers to rapid grid capacity expansion.

In many countries (particularly in the developed world) social opposition to large scale energy infrastructure projects is one of the reasons behind the long planning and permitting timelines for grid infrastructure. Transmission line projects can take up to 10 years, despite construction only taking 1–2 years.[196] Grid optimisation through the application of IGTs could reduce opposition to developments by:

- **Reducing the number of lines** required as IGTs can achieve the required power throughput with less cable and less pylon lines.
- **Reducing the size** of pylon line infrastructure, since optimised cables (such as advanced conductors, DLR-activated lines) droop less and require less material per unit of capacity than conventional wires, resulting in smaller pylon towers which are further apart (subject to safety constraints relating to electrical arcing, uncontrolled discharge of electrical current, similar to a lightning bolt on a small scale).[197]

Other potential options to improve the social acceptance of grid infrastructure includes deploying new, less aesthetically offensive pylon designs (for example the “T-pylon”[198]), and developing green transmission corridors which can be used to increase biodiversity. Beyond reducing visual and environmental impacts, public engagement should also highlight the local economic and social value that infrastructure projects can deliver.[199] Embedding local employment, supply chain opportunities, and wider community benefit into project planning can help build durable public support.[200]

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[196] ETC (2024), *Building Grids Faster: The Backbone of the Energy Transition.*

[197] US DOE (2024), *Pathways to Commercial Liftoff: Innovative Grid Deployment.*

[198] National Grid (2023), *What is a T-pylon?*

[199] For example, in La Guajira, Colombia, renewable energy and grid infrastructure development has met resistance from Indigenous communities concerned about environmental and cultural impacts. The situation underscores the necessity of educating and involving local populations in the planning and benefits of grid developments to ensure equitable and accepted energy transitions. See AP News (2025), *Renewable energy ambitions in northern Colombia collide with Indigenous worries.* Available at https://apnews.com/article/wind-energy-colombia-wayuu-indigenous-resistance-clash-cemetery-renewable-e55077418352f19349dc27b09f1eee18. [Accessed April 2025].

[200] Arup, National Grid ESO & National Gas Transmission (2024), *Hydrogen Production from Thermal Electricity Constraint Management.*

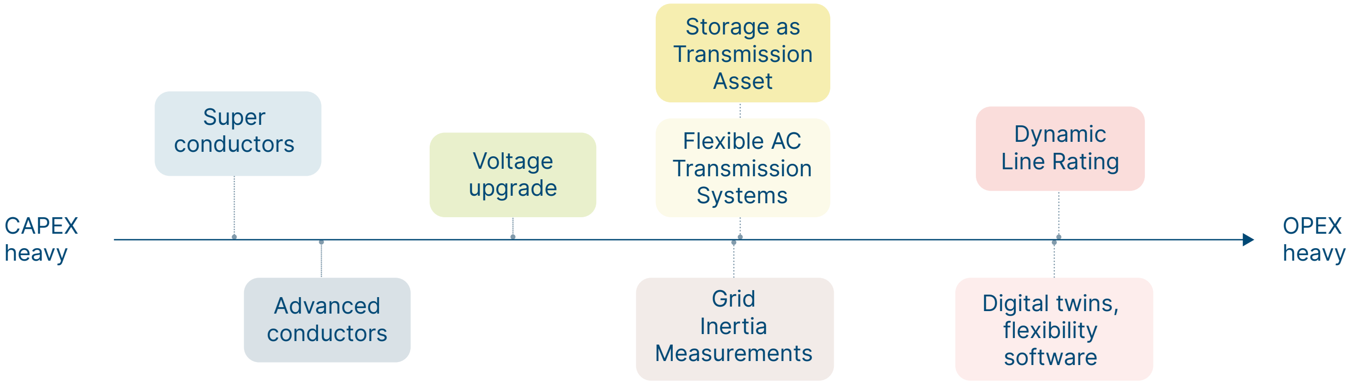
Seizing the very large potential of IGTs will require appropriate regulatory systems which create incentives for transmission and distribution system operators to use an optimal combination of solutions. In several countries, current regulatory systems place incentives on grid operators to reduce operational expenditure but add new capital investment to the regulatory asset base, which is then multiplied by an allowed rate of return and passed through as an increased cost to consumers. This reduces the incentive to use new technologies which reduce capital assets required per kilowatt of power delivered.

Existing regulatory structures of this sort are likely to lead to suboptimal levels of investment in the more CAPEX-heavy types of IGT [Exhibit 2.10].

Exhibit 2.10

The weighting of CAPEX and OPEX is an important consideration in network operator investment plans

Relative CAPEX vs OPEX weighting of total expenditure for selected IGTs



NOTE: SATA = Storage as Transmission Asset. FACTS = Flexible AC Transmission. DLR = Dynamic Line Rating.

SOURCE: Systemiq analysis for the ETC; CurrENT (2024), *Prospects for innovative power grid technologies.*

2.3.3 Optimal location of generation, storage and new large-scale demands

Amongst the drivers of increased grid investment are the development of new sources of renewable supply located away from existing grid networks, and new sources of industrial and commercial power demand. Incentives which encourage the optimal location of supply, demand assets, and storage assets can therefore reduce overall grid investment needs. Key areas of opportunity are:

- Strategic system planning, which aligns future generation, storage, and demand infrastructure with long-term decarbonisation and resilience goals. This includes coordinated spatial and temporal planning to optimise grid use and reduce overall system costs. Examples include the UK's Clean Power Mission and the Strategic Spatial Energy Plan (SSEP), which aims to guide the location of low-carbon assets based on system need, resource availability, and grid capacity.
- Storage located close to areas of transmission or distribution congestion can provide SATA services which has been deployed in several grids around the world, including Germany, the US, and Brazil.[201] Storage close to renewable production assets can also ensure greater utilisation of transmission lines, including long distance HVDC lines (domestic or international) as discussed in Section 1.3.
- Electrification of industrial processes, electric truck charging in logistical areas, and rapidly rising investments in AI related data centres, are creating new electricity demands which will require high capacity grid connection needs; the cost of these can be reduced if price signals incentivise location close to areas of surplus generation or grid connection capacity.[202]

[201] Quanta Technology (2023), *Storage as Transmission Asset Market Study*; P. F. Torres et al. (2024), *Energy Storage as a Transmission Asset—Assessing the Multiple Uses of a Utility-Scale Battery Energy Storage System in Brazil.*

[202] Arup, National Grid ESO & National Gas Transmission (2024), *Hydrogen Production from Thermal Electricity Constraint Management*. This report explores how electrolytic hydrogen production can mitigate thermal constraints on the electricity transmission network by utilising excess renewable energy.

- New sources of electricity supply (whether renewables or nuclear) will impose less grid investment need if there are incentives for these to be built close to centres of demand where this is possible.
- The grid investment consequences of both new demand sources and supply could in some cases be reduced if they can be located where there are already existing high-power grid connections. Decommissioned coal plants could, for instance, be optimal locations for small modular nuclear plants, various types of large storage facility, or energy intensive industrial processes. This opportunity is particularly relevant in countries with significant planned phase-out of coal capacity in the coming years, for example South Africa, where approximately 10 GW of coal generation capacity will be decommissioned over the next ten years.[203] Eskom has already started working on this solution by signing land leases for 2 GW with independent renewable power producers at the Majuba and Tutuka power stations.[204] In the US, a study by the Goldman School of Public Policy at UC Berkeley found that repurposing surplus interconnection capacity at existing fossil fuel sites could enable up to 76 GW of clean energy deployment, including solar, wind, and storage, without requiring new grid connections, saving over $7 billion in costs and dramatically accelerating project timelines.[205]
- Development of international interconnectors could reduce the combination of grid and generation investment needs, compared to scenarios in which countries sought to balance supply and demand within their own territories.

Optimally located solutions will be highly system-specific, reflecting trade-offs between minimising generation costs (which may entail supply from far distant locations), minimising transmission costs and providing energy security. The key priority is therefore to develop market designs and other regulatory approaches which ensure the costs of grid congestion and implications for future grid investment needs are reflected in the price signals (whether relating to grid connection or to electricity prices) which investors consider when making location decisions.

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[203] Blended Finance Taskforce (2023), *Better Finance, Better Grid*.

[204] Eskom (2022), *Eskom signs land lease agreements with independent clean power generators*.

[205] Goldman School of Public Policy (2024), *Surplus Interconnection: Unlocking Clean Energy at Existing Power Plants*.

2.4 Trends in grid costs per kWh

Exhibit 2.11 shows an estimate of how total required grid investment could vary over time.[206] The variations reflect different waves of investment which will occur at different times in specific regions, but the overall pattern is a big increase in global investment between now and 2030, and a roughly constant level of around $850–1,050 billion per annum from then to mid-century.[207] Beyond 2050, investments are likely to decline in most countries, since the period of major new capacity expansion will be complete. However, continued significant investment will be required in currently low income countries, such as in sub-Saharan Africa, as electricity consumption continues to grow rapidly.

Grid investments are typically incurred by grid operating companies which charge consumers annually for grid service on a mix of per connection, per kW and per kWh bases, with different regulation regimes governing allowable costs and rates of returns. Exhibit 2.12 presents estimates of possible resulting grid service costs on a per kWh basis, where this will result from:

- The total payments which grid companies will receive. We have estimated these on the basis of an assumed allowable pre-tax rate of return of 5% real.[208] The actual cost of capital will vary significantly but country, with this cost is typically reflected in the allowable rate of return.
- These total payments then divided by total electricity demand to produce a per kWh charge.

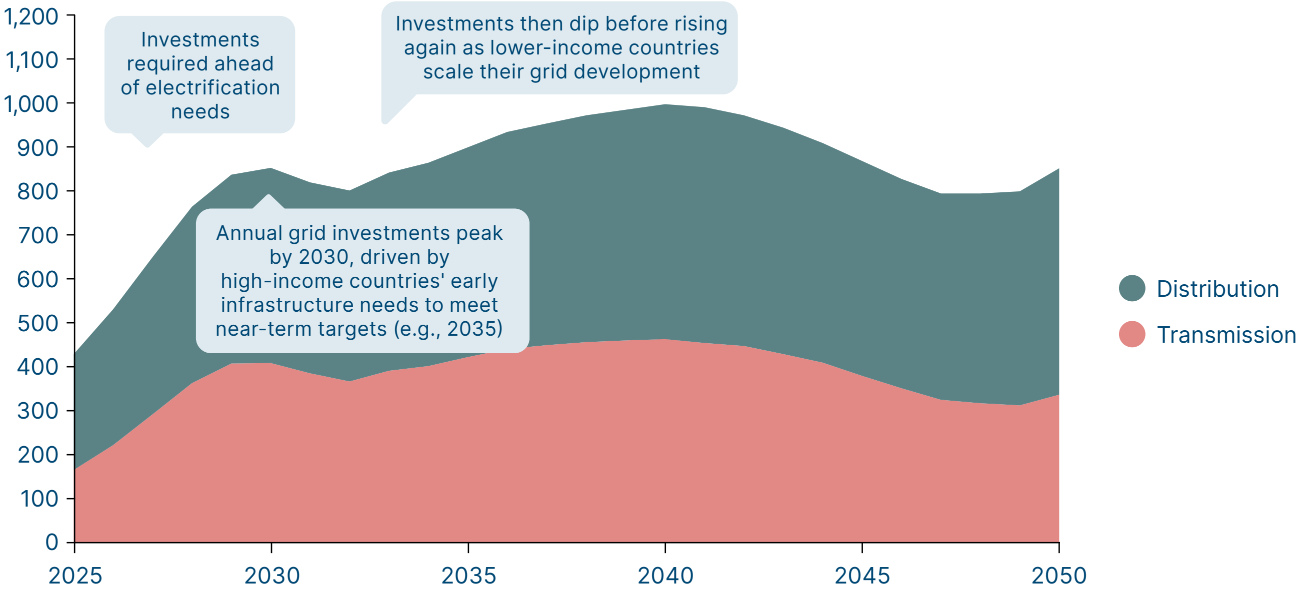
At a global level, this analysis suggests that average grid service costs per kWh could rise slightly from now until 2040 but then fall back to today's level by 2050. The initial increase is due to the upfront investments needed to build and reinforce the grid infrastructure ahead of rising electricity demand. Much of this investment in developing countries is not driven by the energy transition but by expanding energy consumption; and a third involves replacing ageing assets in developed countries.

At the regional level, several key insights emerge [Exhibits 2.11 and 2.12]:

Exhibit 2.11

Global investment in new grid systems will need to rise, with two waves expected to integrate renewables and demand

Annual investment in new power grid system, global, ETC average, 2024–2050
$ billion (real 2023)



SOURCE: Systemiq analysis for the ETC; BNEF (2024), *New Energy Outlook 2024*.

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[206] Systemiq analysis for the ETC; BNEF (2024), *New Energy Outlook 2024*.

[207] BNEF (2024), *New Energy Outlook 2024*.

[208] The discount rate has been set to 5% across all countries to enable a simple comparison across regions in this analysis, however this would vary significantly by country in reality.

- In the **UK**, an initial increase in cost per kWh is driven by upfront investments needed to build and reinforce the grid infrastructure ahead of rising electricity demand. The cost then decreases as demand increases faster than the rate of grid repayment from around 2035.
- **China's** annual grid investments ramp up quickly until 2030, then slow as grid build out approaches completion. Demand in China is expected to continue to increase at a constant rate until 2050, driven by further electrification and growth. The grid cost per kWh therefore decreases after 2030.
- In **India**, grid investment is expected to keep up with demand until 2050, with roughly constant costs per kWh.
- In **Spain**, demand growth accelerates from 2030 onwards, while grid investments rise leading to steadily increasing grid costs per unit demand in the 2020s, which stabilises after 2030, but at a higher level than today.

Given the several assumptions required in this analysis, the figures on Exhibit 2.12 should be treated as illustrative indicators of broad levels and trends, not precise predictions. But they illustrate two key points.

- Grid service cost per kWh are in most countries likely to remain broadly at the same level between now and mid-century.
- However, moderate increases and decreases might result from the balance between total grid investment (and subsequent cost recovery charges) and total electricity demand.

This highlights the vital importance of ensuring a balance between the pace of grid expansion and the pace of electricity demand growth, avoiding either:

- Grid investments failing to anticipate demand growth which as a result might be constrained by grid capacity shortages.
- Electrification proceeding much slower than grid capacity expansion, resulting in increased per kWh charges for grid services[209,210]).

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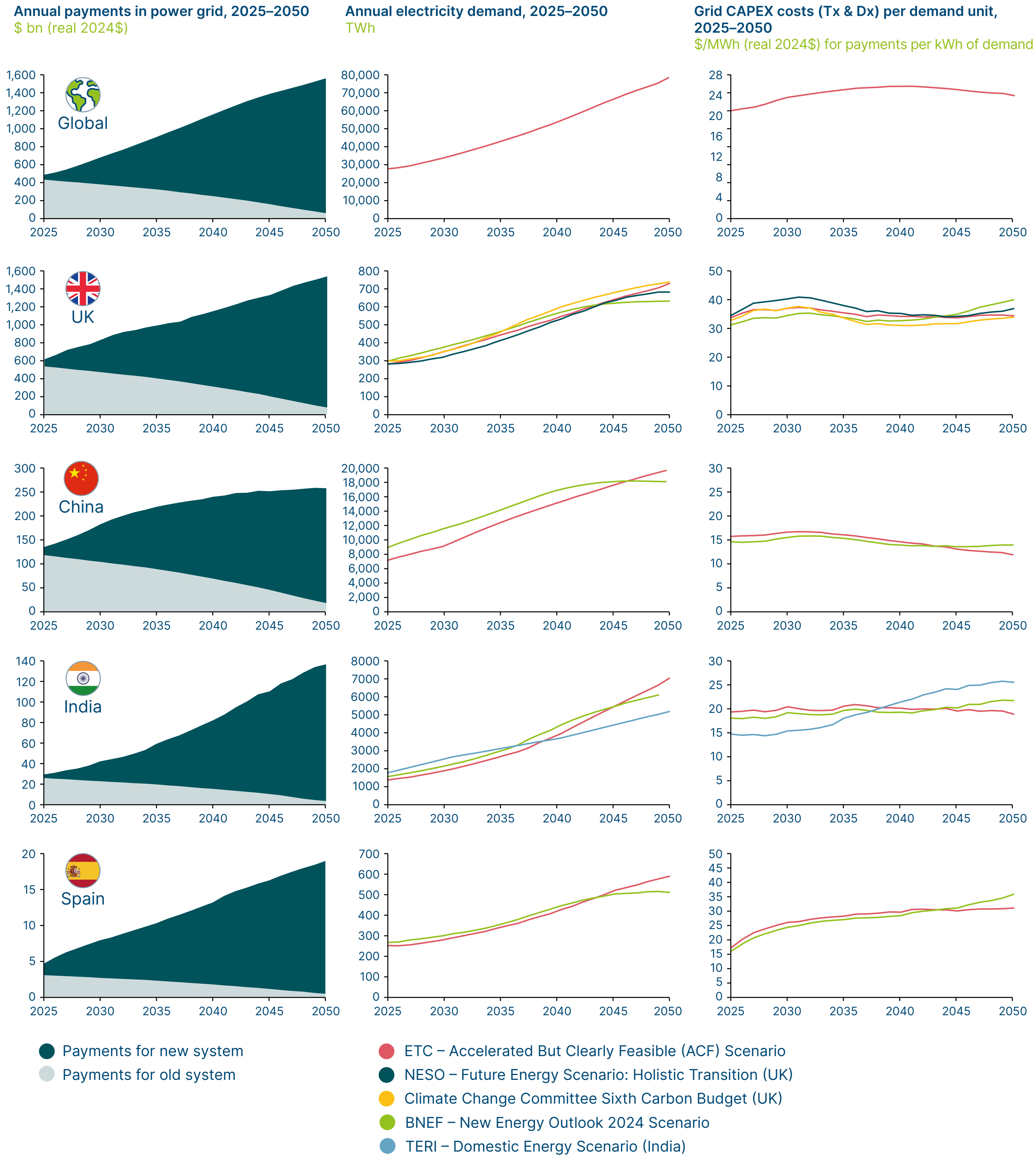
[209] IEA (2023), *Investment in transmission and distribution grids in selected countries, 2015-2022.*

[210] BNEF (2024), *New Energy Outlook 2024*; CCC (2020), *The Sixth Carbon Budget*; NESO (2024), *Future Energy Scenarios.*

Exhibit 2.12

Global electricity supply



Annual payments in power grid, 2025–2050
$ bn (real 2024$)

Annual electricity demand, 2025–2050
TWh

Grid CAPEX costs (Tx & Dx) per demand unit, 2025–2050
$/MWh (real 2024$) for payments per kWh of demand

NOTE: ETC – Accelerated But Clearly Feasible (ACF) is the Energy Transitions Commission's global scenario that outlines a high-ambition but technically and economically feasible pathway to net-zero; TERI is The Energy and Resources Institute; NESO's Holistic Transition is one of the UK's National Energy System Operator's Future Energy Scenarios. It models a coordinated, whole-economy pathway to net-zero by 2050, assuming rapid decarbonisation across power, transport, buildings and industry, enabled by strong policy action and high consumer participation. The old system represents all grid built pre-2024, while the new system represents all grid built during and post-2024. Payment projections assume a 5% interest rate in real terms and 30-year CAPEX repayment timeline. 50% of indirect use for hydrogen production in the ETC's Accelerated but Clearly Feasible (ACF) scenario is included (to reflect the breakdown of grid-connected and off-grid hydrogen production facilities in the scenario). Differences in 2050 demand projections compared to the hourly demand data used in the balancing analysis arise from the different assumptions baked into BNEF and ETC demand trends, and the data sources used for the detailed 2050 breakdown. BNEF figures from the Net-Zero Scenario.

SOURCE: IEA (2023), *Investment in transmission and distribution grids in selected countries, 2015-2022*; BNEF (2024), *New Energy Outlook 2024*; CCC (2020), *The Sixth Carbon Budget*; NESO (2024), *Future Energy Scenarios*; TERI (2024), *Electricity Transition Pathways to 2050.*

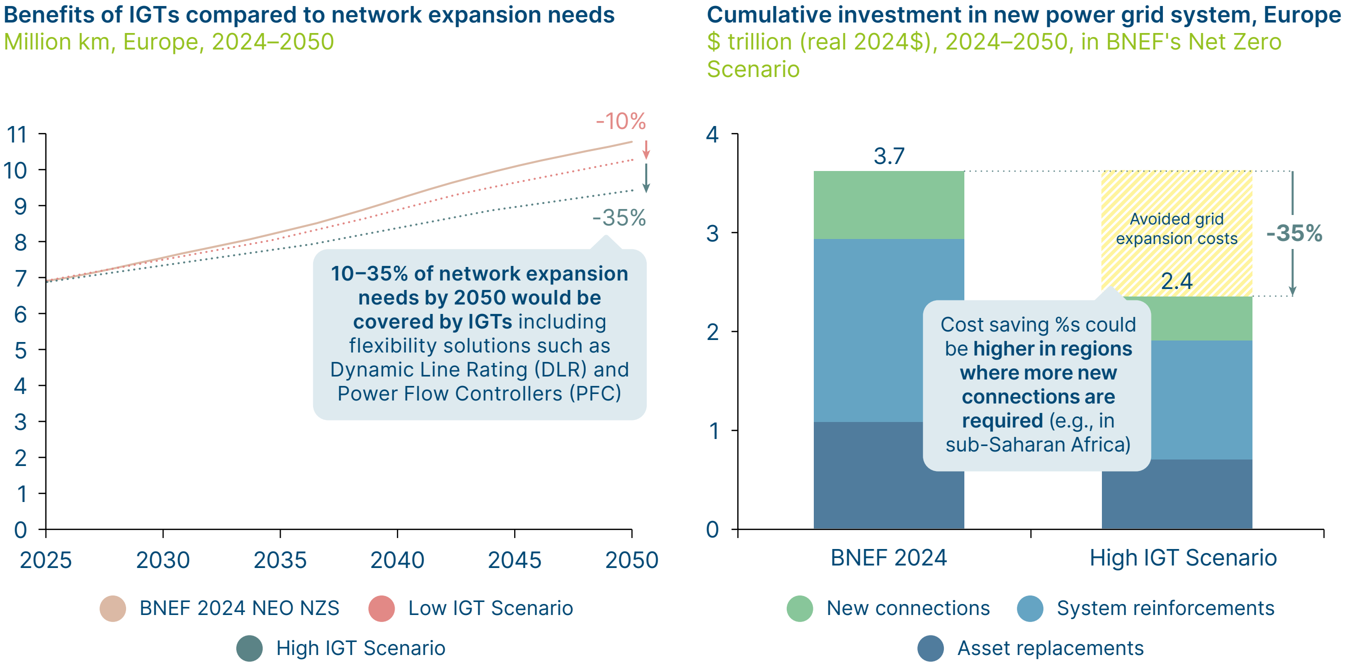
The estimates for grid investment presented above, and the resulting grid service charges per kWh implicitly assume some level of application of the levers which could reduce grid investment costs as discussed in 2.3 – demand side flexibility, IGTs, and optimal location of supply, storage and demand. Maximum use of these levers could significantly reduce grid charges below the baseline levels indicated in Exhibit 2.12.

- As discussed in Section 2.3.2, estimates by CurrENT[211] suggest that IGTs have the potential to increase grid capacity in Europe by 20–40% by 2040,[212] significantly reducing the need for investment in new line and equipment capacity.
- A reasonable deployment scenario suggests that maximum application of IGTs could reduce cumulative required investments in European networks between now and 2050 by $1.3 trillion or 35% as shown in Exhibit 2.13 below.[213]

Policies which encourage maximum possible use of demand side flexibility and IGTs, and encourage optimal location of supply, storage and capacity are therefore vital.

Exhibit 2.13

Innovative Grid Technologies could significantly reduce grid build and reduce CAPEX spending



Benefits of IGTs compared to network expansion needs
Million km, Europe, 2024–2050

10–35% of network expansion needs by 2050 would be covered by IGTs including flexibility solutions such as Dynamic Line Rating (DLR) and Power Flow Controllers (PFC)

Cumulative investment in new power grid system, Europe
$ trillion (real 2024$), 2024–2050, in BNEF's Net Zero Scenario

Cost saving %s could be **higher in regions where more new connections are required** (e.g., in sub-Saharan Africa)

NOTE: We have assumed that IGTs impact all three investment categories in BNEF's Net Zero Scenario: IGTs lower new connection needs by maximising existing and new infrastructure use (though some remote renewables still need connections, new connections leveraging IGTs will require fewer upgrades in future); IGTs delay system replacements by extending grid asset life; and IGTs reduce reinforcement requirements by improving line capacity and utilisation.
SOURCE: Systemiq analysis for the ETC; CurrENT (2024), *Prospects for innovative power grid technologies*; BNEF (2024), *New Energy Outlook*.

2.5 Implementation and policy priorities

Delivering decarbonised and electrified economies will require major expansion, reinforcement and upgrade of transmission and distribution networks, but the scale and cost of this investment could be significantly reduced via the levers described in Section 2.3.

Key implementation and policy priorities are therefore:

- Strategic spatial planning that sets clear strategies for decarbonisation and electrification, which identify and encourage the need for grid investment in anticipation of demand growth but also ensure that demand growth rapidly follows to utilise grid capacity, reducing the cost of grid services per kWh.

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[211] CurrENT (2024), *Prospects for innovative power grid technologies.*

[212] 10–35% offsetting has been assumed here due to BNEF's inclusion of some flexibility in their New Energy Outlook Net Zero Scenario which was used used as a baseline.

[213] Systemiq analysis for the ETC; CurrENT (2024), *Prospects for innovative power grid technologies*; BNEF (2023), *New Energy Outlook Grids.*

- Designing regulatory approaches to support early deployment of IGTs which can reduce both the cost and disruption of infrastructure development. Prioritising IGTs in the short term, namely software based IGTs, alongside strategic system planning, enables operators to gather real-world data and better understand grid constraints. This can inform the timing and scale of major long-term grid reinforcements, allowing "low-regret" investments to proceed early while deferring marginal or uncertain projects to later in the 2030s.
- Maximising the potential for DSF by facilitating the development of time of day pricing and dynamic network tariffs.
- Developing power market designs and system planning approaches that reflect the interdependence between locational decisions and grid investment needs is essential. In some systems, market signals, such as locational pricing, can help guide the siting of generation and flexible assets. However, in more meshed network systems, where transmission lines form a dense, interconnected grid allowing multiple pathways for power flow, like Spain, where both generation and demand are widely distributed and major demand centres are relatively fixed, strategic system planning must be prioritised. This ensures that infrastructure development aligns with broader system needs, rather than relying solely on decentralised market signals.
- Streamlining planning and permitting systems to allow faster development of major new grid infrastructure developments,[214] while seeking social acceptance via use of IGTs to reduce scale of new build where possible and improved pylon designs.
- Identifying potential supply chain constraints, which could slow the pace and increase the cost of grid expansion and developing targeted public policy actions (e.g., development bank finance for new investment) which could overcome these. Key current concerns relate to supply of transformers, HVDC cable and cable laying ships. Skill shortages could exist for linesman and power engineers. Investment in new or expanded copper mines will be needed to ensure adequate long-term supply.[215]
- Revising regulatory frameworks to enable anticipatory investment, by extending planning horizons, spreading the costs of network upgrades more broadly, and allowing greater tolerance for upfront investment risk. These shifts are essential to avoid bottlenecks and support timely infrastructure delivery, even if some assets are not fully utilised immediately [Exhibit 2.14].

The details of these required actions were described in the ETC's 2024 briefing note, *Building grids faster: the backbone of the energy transition* [Exhibit 2.14].[216]

Exhibit 2.14

Key framework elements revisions to enable anticipatory investment

Current state

- **Shorter term planning cycles** (e.g., 5–7 year windows agreed in advance with regulator)
- **Costs typically charged to beneficiary or existing customers**, leading to no/limited proactive investment as

Low risk, but no capacity for anticipatory investment

Lower risk system, but suboptimal choices made from long term system perspective (e.g., incremental decisions which postpone more significant grid upgrades), generally designed for cost efficiency over flexibility and scale

→

Future needs

- **Longer term planning cycles**
- **Socialisation of costs** of unsolicited network upgrades across user
- **Whole-system planning approaches** and cost-optimisation

Higher risk, but can enable anticipatory investment

Increased tolerance for risks which enable decarbonization, even if elements are not later fully utilized and costs for consumers/ taxpayers therefore rise; critical to avoid network bottlenecks

SOURCE: Systemiq analysis for the ETC.

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[214] ETC (2023), *Streamlining planning and permitting to accelerate wind and solar deployment.*

[215] ETC (2023), *Material and Resource Requirements for the Energy Transition.*

[216] ETC (2024), *Building Grids Faster: The Backbone of the Energy Transition.*

3

Total system generation, balancing and grid costs in the long-term and during transition

Chapter 1 concluded with estimates of total system generation and balancing cost in 2050 in four different regional archetypes and Chapter 2 analysed the challenge of building grids, the potential for reduced cost via the use of DSF and IGTs, and the resulting implications for grid service costs per kWh. In this chapter, we look at the implications for total system cost of electricity supply in both the long and short term. Key conclusions are that:

- In the long-term, total system generation and balancing cost per kWh in power systems with high wind and solar shares could be significantly below the cost of today's fossil fuel based systems in low latitude sunny countries, Mediterranean climates, and in China. They could be somewhat lower than recent wholesale electricity prices spikes in high latitude countries which will depend primarily on wind resources.
- It is also vital to focus on the cost of the transition, particularly in many high latitude countries which are currently dependent on more expensive gas supply. Speeding the transition to future potential lower costs will require careful policy design. In early 2026, the ETC will publish a detailed report on the issues relating to consumer power prices over the short- to medium-term.

3.1 Total system generation, balancing and grid costs in the long-term

Exhibit 3.1 combines the analysis of total system generation and balancing costs presented in Chapter 1 and the analysis of potential future grid cost per kWh in Chapter 2. This combination represents total system generation, balancing and grid costs but does not include other bill cost components such as the cost of billing, electricity supplier margins, taxes, or other levies.

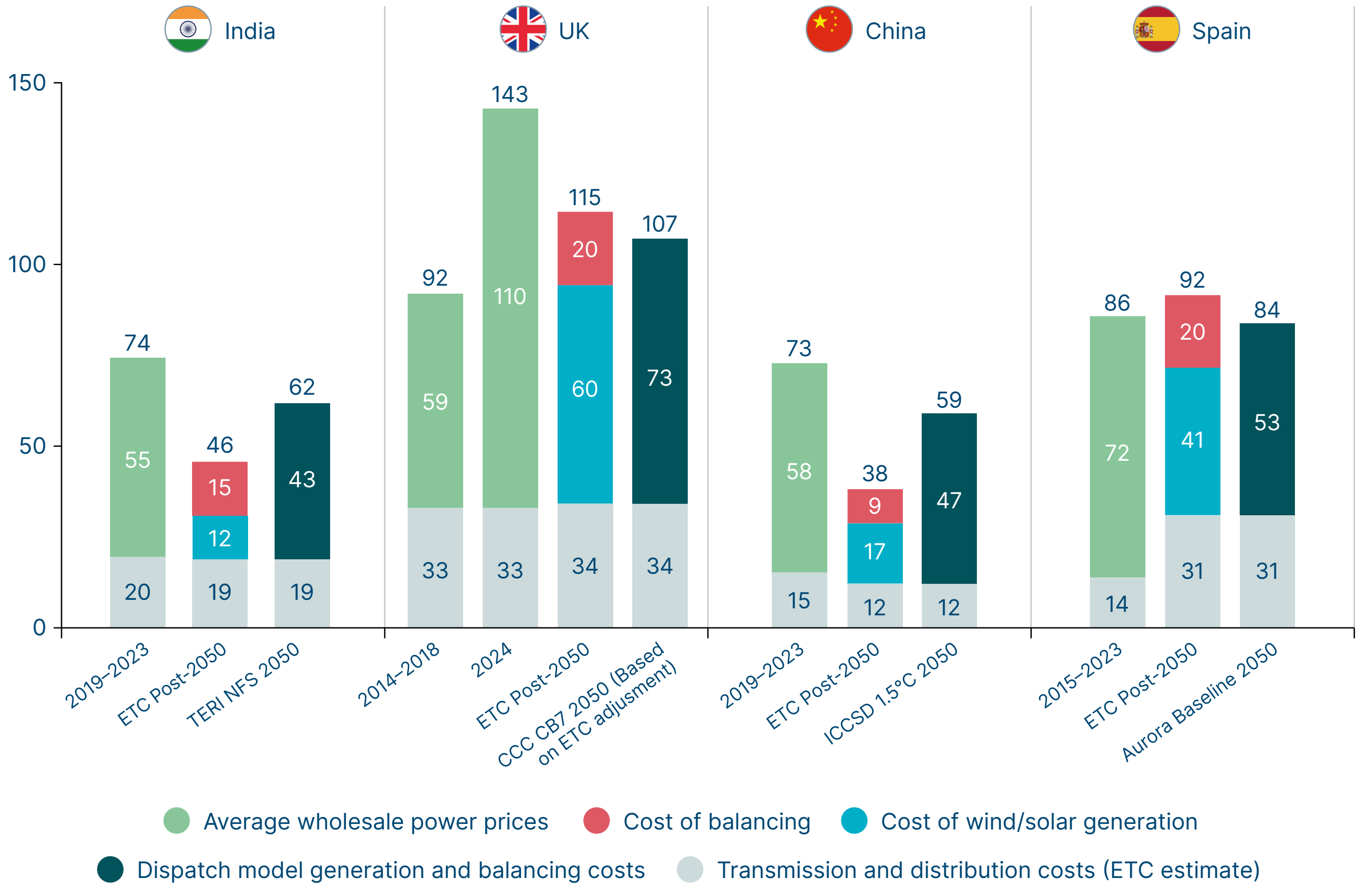
Key findings are that:

- In sunny, low latitude countries (India case study), total system costs in 2050 could be around $50 per MWh. This is significantly below wholesale prices in today's fossil fuel based systems.
- In Mediterranean climate countries (Spain case study), costs could also be significantly below current levels, at around $80 per MWh.

Exhibit 3.1

Total system generation, balancing, and grid costs could be lower than current wholesale prices

Total system costs (generation, balancing, and grids), recent vs post-2050
$/MWh (real 2024$)



NOTE: T&D = Transmission and distribution. T&D costs per MWh have been assumed based on ETC modelling outlined in Chapter 2.

SOURCE: Systemiq analysis for the ETC; BNEF (2025), *LCOE: Data Viewer;* Ofgem (2025), *Wholesale market indicators – Electricity Prices: Forward Delivery Contracts – Weekly Average (GB);* IEA (2023), *Electricity Market Report – Update 2023;* Statista (2024), Average electricity prices for enterprises in China from September 2019 to September 2024; Ember (2025), *Wholesale electricity prices in Europe;* CCC (2025), *The Seventh Carbon Budget;* TERI (2024), India's Electricity Transition Pathways to 2050: Scenarios and Insights; ICCSD (2022), *China's Long-Term Low-Carbon Development Strategies and Pathways;* Aurora (2023), *Long Duration Energy Storage in Spain.*

- In mixed climate countries (China case study), future clean power systems could be achieved at cost significantly below today's wholesale cost of around $75 per MWh.
- In the high latitude archetype (UK case study), costs in 2050 could be around $115 per MWh. This is slightly above the level seen in the 2010s, and slightly below the high levels seen in the early 2020s.

The key difference is driven by total system generation and balancing costs, as explained in Chapter 1. However, differences in grid cost, potential cost of technology and installation also can play a significant role, varying by region:

- **Sunny low latitude countries (e.g. India, Thailand, Mexico, and much of Africa) are projected to have the lowest total system costs.** This is primarily because of the collapsing cost of solar PV and batteries, and the dominance of the diurnal short-duration balancing challenge. In addition, many developing economies are building new grid infrastructure, allowing them to design systems better suited to renewables and modern technologies with fewer legacy constraints and lower need for widespread retrofits.
- **Mediterranean climate countries (e.g. Spain, Australia, California, and Chile) will likely reach similar or lower costs given abundant solar and in some cases wind generation resources.**

- **China, a continental scale mixed-climate country, is projected to enjoy relatively low costs.** This is partly the result of lower capital costs of products and installation. However, it also reflects China's opportunity to use domestic long-distance HVDC lines to connect areas of abundant cheap wind and solar resources with demand centres, and to interconnect different types of renewable resources which have uncorrelated supply patterns. The US should also, in principle, be able to enjoy this continental scale mixed climate advantage, but only if it develops more integrated power systems via investment in long distance transmission.
- **High latitude countries (e.g., UK, Germany, and Japan) are expected to have significantly higher total system costs than in the other regional archetypes.** This reflects a combination of (i) the dominance of wind (and in particular offshore wind) in power generation (ii) the significant need for more expensive ultra-long duration storage (iii) the need for extensive replacement, reinforcement and upgrade of existing grids which were designed around a fossil fuel-dominated system and (iv) higher project installation costs than India and China, and significantly higher product input costs than in China.

While the preceding sections have focused on system-level investment needs and the total cost of delivering reliable, decarbonised electricity, Box G examines a distinct but increasingly critical dimension: the procurement challenge faced by large electricity consumers. As corporates, particularly those with high and continuous demand, such as data centres, industrial manufacturers, and digital infrastructure providers, seek to align with 24/7 clean energy targets and reduce Scope 2 emissions, they must navigate a complex landscape of contracting structures, availability constraints, and cost trade-offs. Box G outlines the evolving strategies being deployed to secure clean power on an hour-by-hour basis, shedding light on the distributional implications of power system design and the emerging demand for commercially viable clean-firm electricity at the end-user level.

BOX G

How can corporates buy clean-firm power?

Corporate electricity buyers, particularly large-scale data centres, manufacturers, and tech companies, are increasingly seeking to decarbonise electricity supply in line with clean power targets and Scope 2 emissions reductions. But while system-level clean power costs may fall, corporates face the distinct challenge of securing clean electricity hour by hour.[213]

The traditional approach, i.e. signing power purchase agreements (PPAs) for solar or wind, provides clean energy at low cost, but only when the sun shines or the wind blows. As the need for firm, reliable clean power grows, buyers face a widening cost and complexity gap between conventional variable renewables and firm, demand-aligned ("shaped").

Today, a range of options are available:

- Standard PPAs for variable renewables: These remain the most common form of clean energy procurement. Corporates contract directly with a project, typically solar or wind, receiving energy and/or certificates tied to its output. Costs can be as low as $40–50 per MWh for utility-scale PPAs, but hourly availability is limited and often misaligned with demand. [214] These PPAs may be "physical" (direct delivery) or "virtual" (financial contracts for difference), with the latter involving additional grid and balancing costs.[215]
- Structured or shaped PPAs [Exhibit 3.2]: These combine multiple clean assets, solar, wind, battery, or firm clean generation (e.g., geothermal), to better match the buyer's hourly demand profile. Google's Clean Transition Tariff with NV Energy is a leading example, using utility-delivered, hourly matched clean power.[216] These structures can significantly boost coverage (some modelling shows above 90% hourly match), but involve more complex contracting and costs that vary widely by region and design.[217,218]
- Renewable Energy Certificates (RECs) or Energy Attribute Certificates: Purchasing renewable energy certificates, particularly hourly-matched RECs, is an option when direct procurement is not viable. However, this model doesn't guarantee additional clean capacity or actual hour-by-hour decarbonisation unless rigorously time-matched.[219]

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[213] BNEF (2022), *Corporate Clean Power Buyers Face Growing Challenges in Securing 24/7 Supply*.

[214] Lazard (2023), *LCOE + Storage v16*.

[215] RE-Source Platform (2023), *Buyers' Guide to Corporate PPAs*.

[216] Google (2021), *Google's Clean Energy Partnership with NV Energy: Enabling 24/7 Carbon-Free Energy*.

[217] Ember (2023), *24/7 Clean Power: How Clean Energy Portfolios Can Reach Over 90% Availability*.

[218] RMI (2022), *Clean Power by the Hour: Advancing Clean Energy Portfolios through Shaped PPAs*.

[219] Canary Media (2023), *Why Data Centers Are Turning to Gas to Keep the Lights On*.

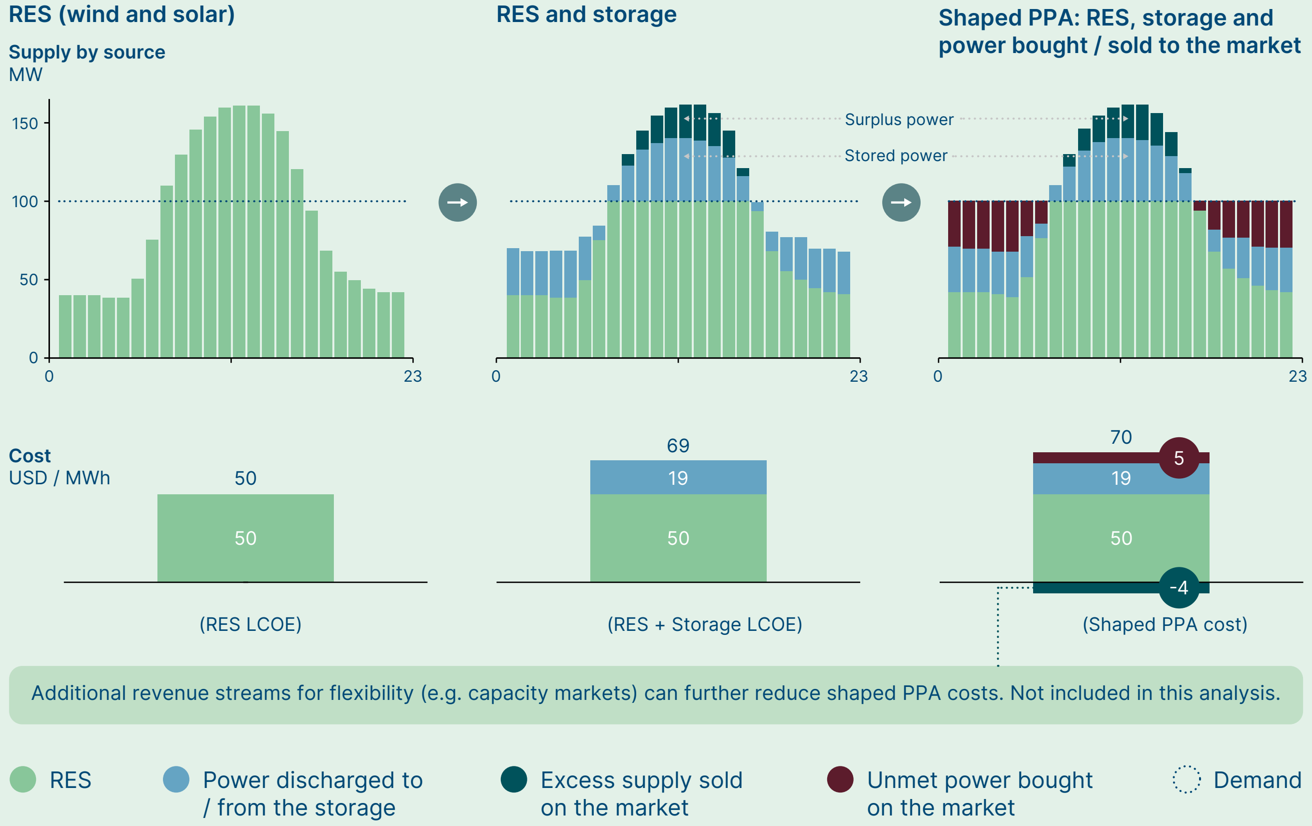
While on-site generation can offer control and visibility, it is rarely pursued at scale. Most corporates prioritise their core business rather than owning energy assets, and physical constraints, such as limited roof or land area, often restrict on-site deployment.[220] In practice, the lack of affordable, scalable clean firm power is creating a gap: in markets where storage remains costly or clean firm capacity is limited, corporates struggle to meet 24/7 decarbonisation goals. In some cases, this has led data centres to install on-site gas turbines to ensure reliability,[221] posing a risk to public and private decarbonisation targets. The emerging priority should there be to develop procurement models, renewable generation, and market structures that unlock firm, hourly-matched clean power at scale and at cost, enabling corporates to lead, not lag, in the energy transition. Hybrid configurations – such as solar co-located with storage – are already being deployed in solar-rich regions to improve hourly match, offering a transitional pathway to reduce fossil reliance while full 24/7 solutions mature.[222]

Exhibit 3.2

Clean power delivered when needed: The role of shaped PPAs

PPA cost components for 80% clean supply-demand matching

2025



Additional revenue streams for flexibility (e.g. capacity markets) can further reduce shaped PPA costs. Not included in this analysis.

NOTE: Calculated as the total cost over energy delivered by solar and wind, including the cost of the full capacity mix divided by the energy delivered by renewables and storage; surplus power from PPA RES assets is assumed to be sold to the day-ahead market at the average price for the cheapest proportion of hours (equal to the share of time with excess generation), while unmet demand is met by purchasing power during the 20% most expensive hours, priced accordingly to reflect peaking asset costs.

SOURCE: Reused with permission from LDES Council and McKinsey (2022), *A path towards full grid decarbonisation with 24/7 clean Power Purchase Agreements.*

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[220] IRENA (2021), *Corporate Sourcing of Renewables: Market and Industry Trends.*

[221] Canary Media (2023), *Why Data Centers Are Turning to Gas to Keep the Lights On.*

[222] *Solar electricity every hour of every day is here – and it changes everything,* Ember, June 2025. The report shows that co-located solar and storage projects are already achieving 60–90% hourly match in regions like California and India, offering a scalable pathway toward clean firm power procurement. Available at: *https://ember-energy.org/latest-insights/solar-electricity-every-hour-of-every-day-is-here-and-it-changes-everything*

3.2 Total system costs during the transition; policies to speed cost reduction

As described above, it is highly likely that by 2050 it will be possible to run power systems with high shares of variable renewables (i.e above 70-80%) at total system costs lower than today's fossil fuel-based systems. However, the cost to consumers during the transition is also important and in several countries, whose current power systems are dependent on imported gas, electricity costs increased significantly in the early 2020s. This has led to misleading claims that the transition to a zero-carbon power system is increasing, rather than decreasing, power system costs.

This section therefore considers:

- The drivers of recent trends in electricity prices in high latitude countries in Europe.
- Likely trends in total system cost over the short term: a UK case study.
- Key policies to speed the transition to potentially lower long-term costs.
- Managing the rundown of gas distribution networks: a significant issue in many high latitude countries.

3.2.1 Recent trends in electricity prices

Over the period of 2021 to 2024, Europe experienced significantly higher electricity prices than those seen before 2020. In a few cases, prices have returned to the previous level but in several they are still significantly higher than in the 2010s [Exhibit 3.3]. Gas prices in Europe drove the increase, which was severely affected by Russia's invasion of Ukraine in 2020. Increases in LNG prices also had an effect on electricity prices elsewhere in the globe. Early stage costs of the transition to zero-carbon power also played a secondary role.

Gas prices setting the marginal cost of electricity: The fundamental driver of volatile electricity prices across certain markets in Europe, particularly in the UK, Germany, Italy, Greece and Ireland, is that the wholesale price of electricity is primarily determined by the cost of gas, even though gas generation accounts for a relatively small and declining proportion of the generation mix. In 2022, natural gas was the price setter for 63% of all hours across the EU even though it only provided 22% of electricity [Exhibit 3.4]. While this dynamic has eased with falling gas prices and increased renewable supply, it remains relevant in many markets.

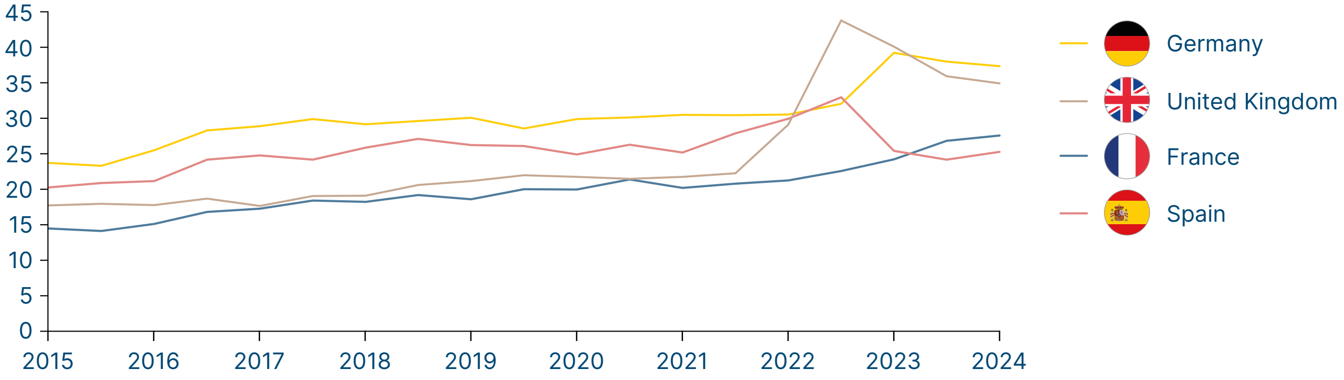
In some cases, for instance in France, large corporates can be shielded from the resulting volatility by fixed price PPAs. At the generator level, an increasing share of renewable electricity supply is covered by forms of partially fixed price contract, e.g., Contracts for Difference (CfDs). But this still leaves the majority of consumers and businesses exposed to prices dictated by the price of gas. Moreover, supplies of renewable or nuclear power which are not covered by fixed price contracts, receive high economic rents when gas prices are elevated.

Exhibit 3.3

Post-crisis electricity price trajectories vary by country due to regulatory and cost structure differences

Electricity prices for household consumers, 2015–2024

£/MWh (nominal)



SOURCE: Systemiq analysis for the ETC; UK Government (2024), *International domestic energy prices.*

Initial costs of the energy transition: Costs related to the early stages of the power system transition, and decisions by government on how to recover these, have played a role in increasing electricity prices in some countries. Exhibit 3.5 shows key determinants of the increase in a typical UK consumer's annual electricity bill between 2015 and 2025, rising from around £450 to reach £1300 in 2022–23 (with the price capped by the UK government bills support during the energy crisis), and then falling to around £900 today. As stated before, the most important driver of this increase was the wholesale price of electricity, set primarily by the marginal cost of gas generation and therefore reflecting variations in the gas price. But four other factors have also been important:

1. **Rising network and balancing costs (around £210 on annual bills):** These reflect a combination of the costs of upgrading the U.K.'s aging electricity grid to handle new renewable generation sources and to build capacity ahead of growth in electricity demand. [223]

   As Chapter 2 discussed, if electrification does not rise fast enough to match increasing grid capacity, grid service cost per kWh will increase. A key contributor to these rising costs is the Balancing Mechanism, operated by the National Energy System Operator (NESO), which brings actual electricity dispatch in line with physically possible transmission. This often results in high "constrain on" payments to gas generators and "constrain off" payments to renewable suppliers. These costs will persist until (i) physical grid constraints are relieved through investment, (ii) generators no longer receive compensation for curtailment, or (iii) demand and supply locations adjust to reduce the need for such balancing interventions.

2. **Policy costs related to early stage subsidies for renewables (around £240 on annual bills):** Looking ahead, renewables have the potential to deliver electricity more cheaply than fossil fuels have. However, subsidies were paid to stimulate the early stages of renewable deployment, when costs were significantly higher. Feed-in tariffs were used to deliver fixed prices for micro-renewables which were well above average wholesale prices. Renewable Obligations Certificates (ROCs), which provided explicit subsidies per kWh above the wholesale price, were subsequently deployed. CfDs can, in theory, result in payments either to or from renewable providers, but until now have mainly been a net cost to the system. Many of these costs will fall away from 2027, before coming to an end by 2037.

3. **Costs related to the Capacity Mechanism (around £20 on annual bills):** Introduced in 2014 under the Energy Act 2013, the UK's Capacity Market (CM) was designed to ensure security of supply by providing payments to capacity providers – including power stations, demand response, and, increasingly, storage – in exchange for being available during periods of system stress.[224] Historically, many of these contracts went to fossil fuel generators, particularly gas-fired power plants.[225] However, recent auctions show a shift toward low-carbon and

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[223] While network costs have been flat in real terms, they have risen in nominal terms on bills at around 50% from £136 a year in 2021 to £198 in 2025. See Carbon Brief (2025), *Factcheck: Why expensive gas – not net-zero – is keeping UK electricity prices so high.* Available at https://www.carbonbrief.org/factcheck-why-expensive-gas-not-net-zero-is-keeping-uk-electricity-prices-so-high/. [Accessed May 2025].

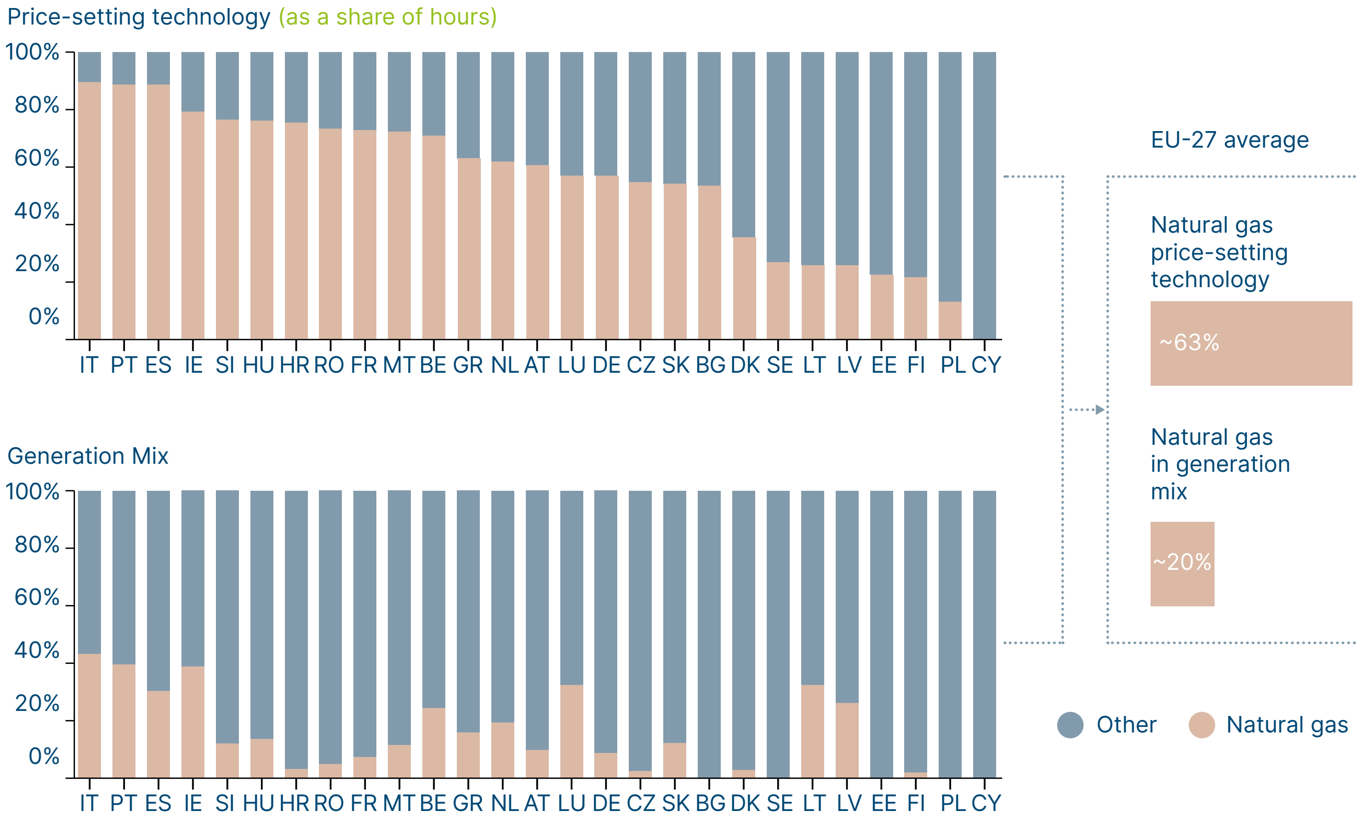
[224] National Grid ESO (2023), *Capacity Market: General Overview.*

[225] Ofgem (2024), *Annual Report on the Operation of the Capacity Market in 2023/24.*

Exhibit 3.4

The European Commission states that the “disproportionate role” of natural gas in electricity price-setting is a key risk to European competitiveness

Price-setting technology per Member State and their generation mix
%, 2022



SOURCE: European Commission (2024); *The future of European competitiveness Part A | A competitiveness strategy for Europe,* https://commission.europa.eu/document/download/97e481fd-2dc3-412d-be4c-f152a8232961_en?filename=The future of European competitiveness _ A competitiveness strategy for Europe.pdf. License: CC BY 4.0.

flexible technologies, including battery storage, which made up over 20% of awarded capacity in the 2024 T-4 auction.[226] While CM costs are passed on to consumers, they represent a relatively small share of bills and play an important role in maintaining reliability as the grid decarbonises.[227]

4. **Other social and environmental levies used (around £60 on bills):** to recover the costs of social and environmental programs from electricity bills rather than general taxation. These include:

    - Assistance for Areas with High Electricity Distribution Costs (AAHEDC) to subsidise the higher network costs in North Scotland.
    - Warm Home Discount, which subsidises winter bill reductions for poorer households and pensioners.
    - Energy Company Obligation (ECO) which subsidises insulation and heating upgrades in poorer households.
    - Smart Meter Net Cost Change to recover the cost of energy suppliers installing smart meters, in line with their obligations.

In addition, it should be noted that the wholesale price of electricity in the UK reflects the impact of carbon pricing within the Emissions Trading Scheme (ETS) and its top up Carbon Price Support (CPS). This is imposed on gas based generation of electricity but not on direct gas use within buildings.

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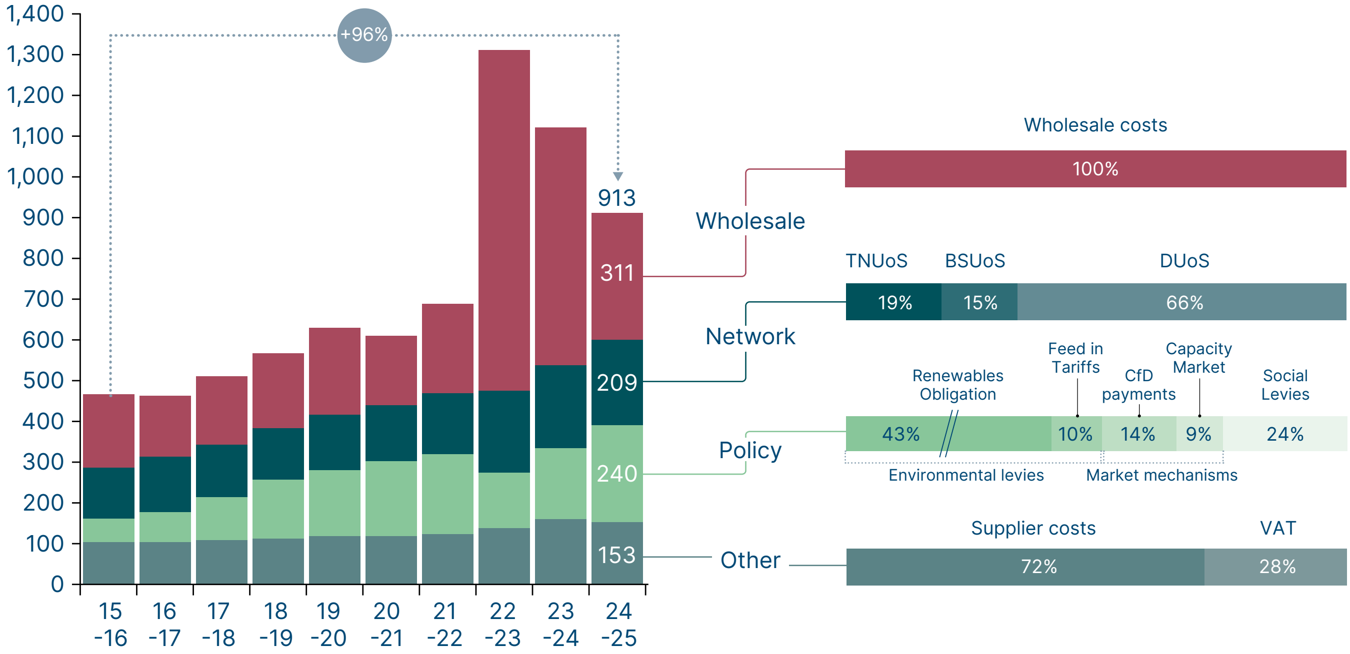
[226] Department for Energy Security and Net Zero (2024), *T-4 Capacity Market Auction Results: Delivery Year 2027/28.*

[227] Carbon Brief (2023), *Factcheck: Why expensive gas – not net zero – is keeping UK electricity prices so high.* Available at https://www.carbonbrief.org/factcheck-why-expensive-gas-not-net-zero-is-keeping-uk-electricity-prices-so-high/. [Accessed May 2025].

Exhibit 3.5

UK electricity consumer bills have increased in the past decade

UK consumer bill component trends, FY15–16 to FY24–25 (left) and FY24–25 breakdown (right)
£ (nominal)



NOTE: Includes subsidies during the energy crisis. Incorporating inflation would reduce the total price per annum. Electricity bills are made of a usage charge (£ per kWh) and standing charge (daily rate). Taxes and levies are split across both. Based on price cap for 3100 kWh/year Single-Rate Metering Arrangement household. Social levies include Energy Company Obligation (ECO), Assistance for Areas with High Electricity Distribution Costs (AAHEDC) Warm Home Discount, smart metre costs. TNUoS = Transmission Network Use of System, BSUoS = Balancing Services Use of System, DUoS = Distribution Use of System, VAT = Value-added Tax.

SOURCE: Ben James (2025), *Electricity Bills*; Ofgem (2024), *Wholesale cost allowance methodology Annex 2*; Ofgem (2024), *Network cost allowance methodology for electricity Annex 3*; Ofgem (2024), *Policy cost allowance methodology Annex 4*; Ofgem (2024), *Smart metering net cost change methodology Annex 5*; AAHEDC (2024), *Charging statements from NESO*.

3.2.2 Possible short-term trends in total system costs

Looking forward, the short- to medium-term trends in electricity prices in Europe and other high latitude countries will be influenced by a balance of favourable and adverse factors:

- Prices will tend to decline over time as older, higher-cost support schemes expire. For instance, the cost to the UK system of Renewables Obligation Certificates (ROCs) will begin falling from 2027, when support ends for projects accredited on or before 25 June 2008, and will be fully phased out by 2037.[228] Feed-in Tariff (FiT) contracts, introduced in 2010, are also expiring, with most due to end by the early 2030s.[229] Early CfD contracts, which had relatively high strike prices, will also begin to drop out of the system over the next decade. Gradually falling technology costs will also tend to reduce the cost of new contracts.
- Volatile global fossil fuel prices will continue to play a role, both through their impact on gas based generation costs and through the resulting economic rents paid to low marginal cost renewable and nuclear generators when gas prices are high.
- Aggressive targets to drive early decarbonisation of power, particularly if facing supply-side constraints, may produce short-term cost increases. As Chapter 1 described, the cost of decarbonising power systems tends to increase as countries approach the “ last mile” of emissions reduction towards zero, particularly in high latitude wind belt countries with significant ultra-long duration balancing requirements.

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[228] *Ofgem (2022), “Renewables Obligation: Guidance for Generators”.*

[229] *BEIS (2019), Feed-in Tariffs Scheme Closure.*

The UK NESO has developed an estimate of the potential costs of achieving the UK's clean power by 2030 target, with the carbon intensity of electricity reaching around 15 g per kWh vs. 125g in 2024 [Box H]. Their scenarios, as shown in [Exhibit 3.6], suggest that:

- The cost per kWh of a zero-carbon power system in 2030 will be 20 to 40% higher than the eventual UK cost in 2050 suggested by both the ETC's illustrative analysis or the CCC dispatch model results.
- In NESO's lower cost "New Dispatch" scenario, the eventual costs are still above the average expected cost in the counterfactual scenario which does not accelerate progress and misses the UK's legally binding carbon targets, resulting in a 2030 grid carbon intensity of 80 gCO_2 per kWh.[230] However, the counterfactual scenario would leave the UK consumer more exposed to gas prices, and in some circumstances would generate a higher system cost per kWh.

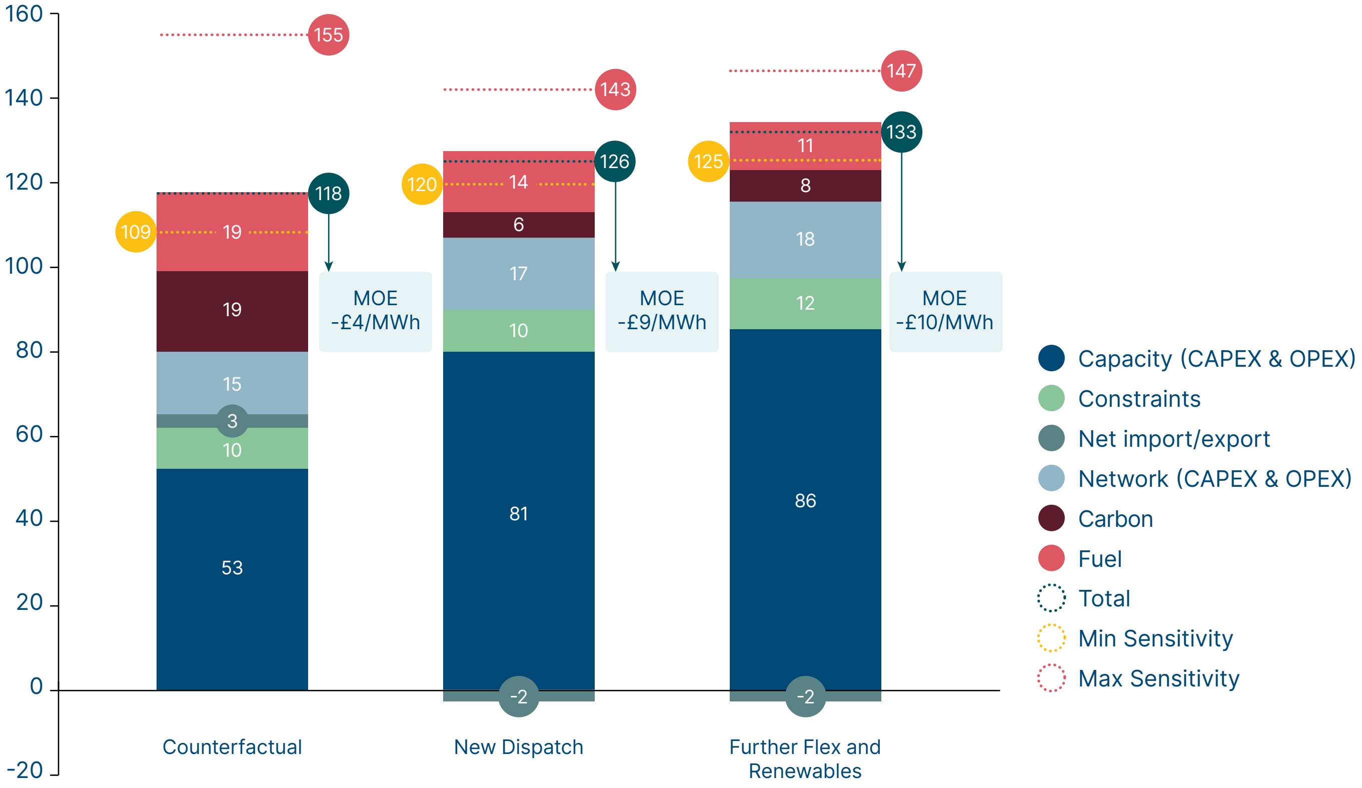
These estimates highlight the importance of:

- Carefully assessing the optimal pace of progress towards completely decarbonised power systems. A slower path of reduction once low carbon intensity levels have been achieved (e.g., below 50g per kWh) could help moderate short-term costs and prices. This would in turn make it easier to achieve rapid electrification which, as discussed in Chapter 2, needs to keep pace with power sector decarbonisation.
- Considering the alternative options for "last mile" decarbonisation discussed in Section 1.5.5.
- Implementing policies which speed the transition to the potentially lower costs of highly renewable systems.

Exhibit 3.6

NESO estimate that meeting the 2030 clean power target will slightly increase system costs compared to the counterfactual

2030 Annuitised system costs per unit of electricity with sensitivities
£/MWh (real 2024£)



NOTE: MOE = Merit Order Effect, reducing payments to some older plants.

SOURCE: Adapted from NESO (2024), *Clean Power 2030, Advice on achieving clean power for Great Britain by 2030.*

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230 NESO (2024), *Clean Power 2030, Annex 4: Costs and benefit analysis.*

Box H

Case Study: the UK's 2030 Clean Power target is expected to decrease costs for consumers compared to today's system, despite slightly higher system costs on an annuitised basis

In 2024, the Labour government adopted a 2030 Clean Power target for the UK, and declared a national Mission around the clean power goal.[231] Subsequently, the UK's NESO outlined a feasible pathway to achieving the government's commitment to clean power by 2030.[232] The clean power target was defined by NESO as "at least as much power being generated from clean sources as Great Britain consumes across the year, and when unabated gas generation makes up less than 5% of Great Britain's generation in a typical weather year". [233]

To test the upper bounds of decarbonisation ambition, NESO, modelled two illustrative scenarios that achieve 15 gCO_2/kWh by 2030.[234] These were not adopted as official targets but served to assess technical and economic feasibility under more aggressive assumptions than the CCC's proposed 50 g/kWh 2030 target. Both NESO scenarios demand deeper and faster transformation of the power system, including significantly more renewables, storage, and grid infrastructure:

- Further Flex and Renewables assumes very high deployment of renewables, storage, and demand side flexibility, with no new low-carbon dispatchable power. It achieves 15 gCO_2 per kWh (excluding energy from waste and combined heat and power) at a system cost of £135 per MWh (~$170 per MWh, real 2024).
- New Dispatch includes greater reliance on new low-carbon dispatchable power such as CCS, hydrogen, and nuclear. It achieves the same carbon intensity at a lower system cost of £125 per MWh (~$160 per MWh, real 2024).

While these clean power scenarios are estimated to entail slightly higher annuitised system costs than today's system, due to increased curtailment and investments in storage and grids, overall electricity prices for consumers are expected to be around £10 per MWh lower under a clean power system. This decrease is driven by lower generation costs (through reduced exposure to gas and carbon prices), reduced infra-marginal rents, the phasing out of levies for older renewable support schemes as their contractual periods end, and further potential bill reductions through energy efficiency measures (which could decrease household electricity usage by 5-10%).

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[231] Carbon Brief (2024), *Analysis: How the UK plans to reach clean power by 2030*. Available at https://www.carbonbrief.org/analysis-how-the-uk-plans-to-reach-clean-power-by-2030/#:~:text=It adopted a definition with,5% coming from unabated gas. [Accessed January 2025].

[232] UK Government (2024), *Clean Power 2030 Action Plan*.

[233] NESO (2024), *Clean Power 2030, Advice on achieving clean power for Great Britain by 2030*.

[234] CCC (2024), *The Seventh Carbon Budget: Reducing Emissions from the UK Power Sector*.

3.2.3 Policy actions to speed the transition to lower power system costs

Key policy actions to speed the transition to the potentially lower price systems of the future include:

1. **Reducing the number of hours in which gas sets the wholesale electricity price requires a combination of structural and operational reforms**.
   - Scaling renewable generation rapidly through well-designed two-way CfDs, corporate PPAs, and auctions remains critical to reducing exposure to volatile fossil fuel prices. Locational marginal pricing (LMP) or zonal pricing has also been proposed as a means to better reflect local supply-demand dynamics and transmission constraints. While LMP does not break the link between electricity prices and marginal cost – since gas can still be the marginal unit locally – it can reduce the exposure of consumers in renewable-rich areas by ensuring they are not paying a system-wide price set by distant gas plants. In parallel, modernising balancing mechanisms, such as redispatch tools and system software, can improve operational efficiency by increasing visibility of low-carbon flexibility sources like batteries, helping to displace gas in real-time dispatch. Some proposals go further, suggesting the creation of a separate market for gas-fired generation to structurally decouple gas plants from the marginal pricing mechanism. Together, these approaches can reduce consumer exposure to gas price volatility while supporting more efficient and decarbonised system operation.[235]
2. **Rebalancing policy costs across gas, oil and/or government fees, levies or taxation.**
   - Renewable energy targets in the EU (and previously in the UK) were set relative to total final energy consumption, including electricity, gas, and oil, but were primarily delivered via the power sector, where deployment was cheaper and faster. As a result, the cost burden has fallen disproportionately on electricity consumers, even though the benefits support decarbonisation across the whole energy system. Rebalancing these costs, by allocating some to gas or general taxation, would ensure a fairer distribution and help make key electrified technologies (such as heat pumps and EVs) more competitive against fossil-fuel alternatives.

     In the UK, for example, carbon pricing mechanisms such as the UK ETS and Carbon Price Support currently add significantly to the cost of gas-fired power generation, but are not imposed on direct gas use within buildings, reducing the incentive to electrify.[236]

     In addition, it may be appropriate to fund certain socially motivated programmes (e.g., fuel poverty support) via public budgets rather than through electricity bills. Legacy renewable energy contracts could have near term cost reductions through life extensions to support refurbishments or life extensions.
3. **Time-of-use tariffs/real-time pricing and dynamic network tariffs,** enable consumers to shift their electricity use to low, off-peak electricity costs rather than average costs. These are important tools to align consumer demand with wind and solar supply and to reduce gas reliance in the system. Scaling storage and demand side flexibility together helps ensure that consumer demand can play into the system instead of gas.
4. **Incentivise self-reliance across residential and industrial properties**, for example through integrating clean technologies (including rooftop solar, heat pumps, and EVs). When supported by appropriate tariffs and regulation,

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[235] Stonehaven (2025), *Managing Decline: A Regulated Asset Base for Legacy Gas in the Age of Clean Power*. Available at: https://www.stonehavenglobal.com/managing_decline_a_regulated_asset_base_for_legacy_gas_in_the_age_of_clean_power. [Accessed 28 May 2025].

[236] Ed Hezlet (2025), *The Missing Chart from the UK Energy Strategy*. Available at https://wattdirection.substack.com/p/the-missing-chart-from-the-uk-energy. [Accessed May 2025].

this has a significant potential to reduce bills (to zero in some cases, in line with Octopus' Zero Bill homes initiative in the UK[237]) but also wider network costs as more homes increase their energy self-sufficiency. However, benefits depend on how systems are integrated and managed; in some cases, especially where tariff structures don't reflect true system impacts, self-generation could increase per-customer network costs – increasing costs particularly for those who are unable to afford or install their own generation.

5. **Reforming grid cost recovery frameworks, including extending amortisation periods for grid investments.** As power systems undergo major grid upgrades, spreading capital cost recovery over longer periods can reduce near-term tariff impacts and help ensure affordability during the transition. Regulatory adjustments to grid depreciation schedules can smooth the cost curve for consumers while maintaining necessary investment flows.

3.2.4 Planning for gas network decommissioning

It is clear that the only way to achieve a very low and eventually zero carbon global economy is through massive clean electrification including the electrification of building heating as described in the ETC's recent report on *Achieving Zero-Carbon Buildings: Electric, Efficient and Flexible.*[238]

As a result, countries which rely on gas to meet extensive building heating needs will have to face the costs of eventually closing down their gas distribution networks. Parts of the long-distance gas transmission and storage network may be repurposed to support the transport of CO_2 (for CCS applications) or of hydrogen: and parts may continue to transport natural gas used by large industrial sites equipped with CCS or by gas peaker plants within power systems. However, overall there are relatively limited opportunities to repurpose gas distribution grids in decarbonised energy systems.

The countries most affected by this challenge are high latitude ones such as Canada, Europe, Russia, and Japan, together with colder regions within mixed-climate, continental-scale countries such as the US and China – though the scale of the Chinese gas grid remains limited due to a historic reliance on coal rather than gas for residential heating. This challenge also applies to cooler southern regions in the Southern Hemisphere, such as the state of Victoria in Australia, which has historically been gas-dependent for heating but is now transitioning away from gas through policies like the Gas Substitution Roadmap, including a ban on most new gas connections.[239]

Several jurisdictions have begun to develop clear regulatory frameworks to manage the decommissioning process. For example:

- In the United States, California has initiated regulatory proceedings to explore targeted electrification and the phased retirement of gas infrastructure.[240]
- In Europe, the 2023 passage of Article 52b requires gas distribution system operators to prepare network decommissioning plans.

Independent bodies such as the Regulatory Assistance Project (RAP) have provided international guidance on managing gas grid transitions in support of net-zero objectives. [241] To enable an orderly and equitable transition, governments should focus on:

- Establishing regulatory frameworks and national-level oversight for gas network decommissioning across both transmission and distribution systems.
- Ensuring that infrastructure planning is aligned with decarbonisation pathways, for instance by incorporating decommissioning plans into long-term network development scenarios.[242]
- Clarifying the long-term role of low-carbon gases and ensuring consistent standards for their use in infrastructure planning.[243]

Developing plans for how to recover the remaining costs of the gas distribution network as the number of users declines is important. If costs are recovered via connection charges per customer, the resulting increase in cost per user may in some cases be socially unacceptable. A balance will therefore have to be struck between creating incentives for gas users to electrify and avoiding severe income effects by shifting some of the costs from users to public budgets.

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[237] Octopus (2025), *100,000 Zero Bills homes by 2030.*

[238] ETC (2025), *Achieving Zero-Carbon Buildings: Electric, Efficient and Flexible.*

[239] State of Victoria (2023), *Victoria's Gas Substitution Roadmap.*

[240] California Energy Commission (2024), *Strategic Pathways and Analytics for Tactical Decommissioning of Portions of Gas Infrastructure in Northern California.*

[241] Regulatory Assistance Project (2023), *Policy and Regulatory Options to Manage the Gas Grid in a Decarbonising Europe.*

[242] Climate Action Network (2024), *Gas Package Analysis: The Good, the Bad and the Ugly of the revised Directive and Regulation.*

[243] European Commission (2024), *Commission launches consultation on draft methodology for low-carbon hydrogen.*


NATURAL GAS

4

Key enablers for cost effective power system development

Chapters 1, 2 and 3 have illustrated that it will be possible to build power systems with very high levels of wind and solar generation and greatly expand transmission and distribution grids, while keeping total system generation, balancing and grid costs per kWh below, and in some cases significantly below those seen in today's fossil fuel based systems. Achieving this will require effective policy design and implementation.

The immediate priorities should be to rapidly deploy wind and solar to displace fossil fuel generation, and meet growing electricity demand, and to unlock grid capacity through a combination of investment ahead of need and new flexible grid technologies (including demand side flexibility).

Previous ETC reports have described many of the actions required, including:

- **Appropriate market design, such as deploying two-way Contracts for Difference (CFDs)** to provide revenue certainty and lower the cost of capital for renewable projects – discussed in the ETC's 2021 report*: Making Clean Electrification Possible.*[245]
- **Reforming planning and permitting processes**, particularly by setting clear national deployment targets, enabling digitalisation of permitting, and improving local administrative capacity – covered in the ETC report *Streamlining Planning and Permitting to Accelerate Wind and Solar Deployment.*[246]
- **De-bottlenecking clean energy supply chains**, by expanding critical material supply, scaling and diversifying manufacturing bases, and enabling trade in clean energy technologies – covered in *Better, Faster, Cleaner: Securing Clean Energy Supply Chains* and *Material and Resource Requirements for the Energy Transition.*[247]
- **Scaling grid infrastructure investment and delivery**, through anticipatory planning and investing, coordinated spatial development, and regulatory reform – covered in the ETC briefing note, *Building Grids Faster.*[248]

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[245] ETC (2021), *Making Clean Electrification Possible: 30 Years to Electrify the Global Economy.*

[246] ETC (2023), *Streamlining Planning and Permitting to Accelerate Wind and Solar Deployment.*

[247] ETC (2023), *Better, Faster, Cleaner: Securing Clean Energy Technology Supply Chains;* ETC (2023), *Material and Resource Requirements for the Energy Transition.*

[248] ETC (2024), *Building Grids Faster: Accelerating Grid Infrastructure to Meet Demand for Clean Power.*

This chapter highlights six categories of government and private sector action required to address the specific challenges of system balancing and optimal grid design and operation [Exhibit 4.1]. These include:

- Setting a strategic vision supported by appropriate planning.
- Ensuring that key aspects of market design reduce investor risk and support efficient capital allocation by incentivising the deployment of needed technologies (such as medium-long duration energy storage) and reducing their cost of capital through predictable, multi-revenue streams.
- Providing grid regulations that limit any delays in the development and connection of new technologies to the grid, and ensure that they are being valued fairly on the system.
- Applying digital and AI-based capabilities to manage power systems more efficiently.
- Addressing potential supply chain and workforce bottlenecks.
- Consumer engagement and product design to enable demand side flexibility.

Exhibit 4.1

Six key enablers for power systems transformation

SOURCE: Systemiq analysis for the ETC.

4.1 Strategic vision and planning

The transformation from fossil-based systems to clean power systems dominated by wind and solar and supported by storage and demand side flexibility requires a major shift in how power systems are planned and governed. Unlike in traditional systems – where dispatchable power plants could be scaled incrementally with limited coordination – future systems will require integrated and anticipatory development of generation, transmission, storage, and digital infrastructure.

A clear and credible strategic vision is essential to guide this transformation. It must go beyond headline decarbonisation goals to set specific, time-bound deployment targets for renewables, grids, storage, and flexibility, providing a framework within which individual investors and operators can confidently act. This vision must be underpinned by robust institutions capable of coordinating across the system and ensuring that investments align with long-term system needs.

Strategic infrastructure plans can operationalise this vision by providing a coordinated blueprint for development across generation, transmission, and flexibility resources. In Great Britain, the Centralised Strategic Network Plan (CSNP)[249] and the Strategic Spatial Energy Plan (SSEP)[250] are designed to enable anticipatory grid and offshore wind development aligned with future system needs. Similarly, the Offshore Network Development Plan (ONDP) developed by ENTSO-E[251] provides a Europe-wide view of integrated offshore wind and transmission infrastructure, intended to support cross-border collaboration and accelerate clean energy deployment in the EU.

Countries must design realistic planning processes that reflect their capacity to deliver and implement policies effectively across regions or jurisdictions. In the UK, a central transmission operator (NESO) enables national coordination of planning and investment. In contrast, the European Union lacks a comparable central body with decision-making authority; ENTSO-E facilitates technical cooperation, but cross-border infrastructure often stalls due to the need for consensus among member states. Strengthening regional coordination platforms or enhancing the mandate of EU institutions could accelerate progress. In the US, transmission planning is split among regional operators with varying mandates. Federal action, via the Department of Energy (DOE) or Federal Energy Regulatory Commission (FERC), can help set strategic direction, while states collaborate through regional planning alliances.

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[249] NESO (2024), *Centralised Strategic Network Plan: Supporting the UK's Net Zero Delivery*.

[250] Scottish Government (2023), *Strategic Spatial Energy Plan: Delivering Net Zero Infrastructure in Scotland*.

[251] ENTSO-E (2023), *Offshore Network Development Plan: A Pan-European Vision for Offshore Grid Expansion*

In all settings, effective system planning requires:

- Clear institutional responsibility for long-term planning.
- Authority to coordinate across regional and sectoral boundaries.
- Alignment across generation, transmission, distribution, storage and demand side investment where possible.

This planning framework should deliver:

- Clear and ambitious emissions intensity reduction targets aligned to overall net zero goals with sufficiently long time horizons to guide infrastructure investment. For example, Chile has implemented a 30-year energy planning process that informs national transmission planning and aligns generation and grid development with climate goals.[252]
- Indicative clean capacity targets covering both generation and storage. In India, the government's consistent policy support and long-term targets under the National Electricity Plan and Renewable Energy Roadmap have played a key role in accelerating investment in battery storage and grid-scale renewables. The regulatory clarity provided by the Central Electricity Regulatory Commission (CERC),[253] including guidelines for ancillary services and storage participation in markets, has given investors confidence to finance large-scale projects.
- Medium term auction schedules that give investors visibility and certainty across different asset classes.

These will need to be underpinned by:

- Sophisticated models and forecasting capabilities, for instance within electricity system operators, to model likely developments of demand, generation, storage and transmission capacity and the degree of consumer response to demand side flexibility opportunities. This modelling can help anticipate possible imbalances between different parts of the system e.g., transmission congestion constraints.
- Political will and regulatory clarity, as seen in India, where consistent national targets, regulatory guidance from CERC, and market rules for storage and ancillary services have enabled large-scale investment.
- Anticipatory funding mechanisms, ensuring that key infrastructure, especially grid and storage capacity, is built ahead of demand, while electrification policies scale demand in step with system capacity.

4.2 Market design to incentivise efficiency and reduce cost of capital

The financial viability of projects which meet the balancing challenge will be heavily influenced by the structure of contracts within the markets for electricity capacity and other services. Electricity markets around the world typically buy and sell electricity ahead in real time (known as "wholesale pricing") with pricing "windows" of 15 or 30 minutes duration, with additional ancillary services being procured directly by the system operator closer to real-time in order to balance the system. Over time, the complexity of market design has increased as additional mechanisms have been introduced; these include fixed or partially fixed contracts for renewables (feed-in-tariffs, or CfDs), capacity payments, payments for more sophisticated ancillary services (e.g., sub-second balancing), and payments to constrain capacity on or off if the outcome of market trading cannot be physically delivered.

While existing arrangements and reform priorities vary significantly between countries, four areas emerge as particularly important across many national contexts [Exhibit 4.2]. These mechanisms are especially crucial for enabling investment in newer technologies – such as long-duration storage, flexible demand, and grid-forming assets (power system technologies, such as advanced inverters or certain types of storage, that can actively stabilise the grid by setting voltage and frequency) – which often face high upfront costs and lack stable revenue models:

- Mechanism 1: Ensuring market access and revenue stacking for all eligible technologies, so that new storage or flexibility options, including DSF, can participate across wholesale, balancing, and ancillary markets – helping to reduce revenue risk and cost of capital.
- Mechanism 2: De-risking emerging technologies through reformed market structures and targeted mechanisms, including more flexible capacity markets and long-term contracts such as PPAs, CfDs, and cap-and-floor models.
- Mechanism 3: Bridging early-stage innovation gaps via public R&D and demonstration funding, which is essential to accelerate commercial readiness of novel solutions like ultra-long duration storage or grid-forming inverters.
- Mechanism 4: Strengthening price signals through better use of locational and temporal pricing and carbon markets - to guide investment and operation decisions that align with overall system efficiency and reduce long-term costs.

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[252] ETC (2024), *Building Grids Faster: The Backbone of the Energy Transition.*

[253] India Central Electricity Authority, *National Electricity Plan (Volume I – Generation)*, 2023. Available at: https://cea.nic.in/national-electricity-plan. [Accessed May 2025].

Exhibit 4.2

Four mechanisms to address market design challenges

Challenge		Mechanism
1	**Limited market access**	• Enabling market access for all eligible technologies • Ensuring revenue stacking is available so that technologies have access to multiple revenue streams
2	**Uncertain and risky revenue streams**	• Providing de-risking mechanisms for emerging critical technologies through ∘ Reforming existing markets e.g., capacity markets to better value flexibility. ∘ Providing contracted mechanisms such as PPAs, CFDs, Cap and Floor Schemes, Tolling Agreements and Feed in Tariffs.
3	**Targeted support for new technologies**	• Providing early-stage R&D funding to enable early-stage innovation commercialisation gaps to be bridged.
4	**Inadequate pricing signals**	• Strengthening price signals by exploring opportunities presented by locational signals and carbon pricing.

NOTE: PPAs = Purchasing Power Agreements. CfDs = Contracts for Difference.

SOURCE: Systemiq analysis for the ETC.

4.2.1 Addressing limited market access: enabling multiple revenue streams

The initial deployment of battery storage and other emerging flexibility technologies has been primarily driven by participation in ancillary services markets, which focus on very short-term grid balancing challenges. By contrast, large-scale hydropower assets, including pumped hydro, have often been developed through different investment models, such as public infrastructure funding or integrated utility planning. To date, most storage deployment has been short-duration, in part because these assets have been able to access established markets. However, as system needs evolve, there will be a growing requirement for medium- and long-duration storage, which must also be able to access a broad range of markets to ensure viable investment and effective system contribution. Looking forward, investment on the scale required to achieve the different elements of balancing described in Chapter 1 will likely need to be remunerated by several different revenue streams.

Exhibit 4.3 describes four types of market in which storage and flexibility providers could participate. Market access across these areas is growing and moving beyond relying solely on ancillary services. For example, the Tehachapi Energy Storage Project in California successfully accessed multiple revenue streams, including wholesale market participation, energy arbitrage, frequency regulation, and capacity payments.[254] Similarly, in South Australia, large-scale battery projects such as the Hornsdale Power Reserve have benefited from stacking revenues across frequency control ancillary services, energy arbitrage in the wholesale market, and network support services.[255]

Similarly, in the UK, our analysis of storage revenues shows that reliance on a single market, such as wholesale, can leave assets with insufficient revenues to cover costs. This is highlighted in Exhibit 4.4, which illustrates that when battery storage systems leverage revenue stacking - combining earnings from capacity markets, ancillary services, balancing mechanisms, and wholesale markets - total revenues increase, making storage financially viable and supporting a robust business case.

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[254] Southern California Edison (2022), *Tehachapi Energy Storage Project: Advancing Grid Reliability and Renewable Integration.* Retrieved from https://www.sce.com

[255] Neoen (2020), *Hornsdale Power Reserve – Case Study on the Benefits of Grid-Scale Battery Storage*

Exhibit 4.3

Four electricity markets should be available to storage and flexibility assets

Merchant electricity markets

Ancillary Services	• **Grid support functions** that ensure stability, reliability, and security of the electricity system. • **Key services include** frequency regulation, voltage support, spinning reserves, ramping, and load balancing.
Capacity Markets	• **Ensure long-term grid reliability** by procuring sufficient generation, storage, or flexibility resources to meet peak demand. • **Key services include** capacity markets, resource adequacy markets, decentralised capacity obligations.
Wholesale Market	• **Facilitates the buying and selling of electricity** between generators, suppliers, and traders before reaching end consumers. • **Key services include** day-ahead, intraday, real-time market.
Balancing Mechanisms	• Allow system operators to **manage real-time supply and demand** imbalances by dispatching flexible resources. • **Key services include** e.g., UK Balancing Mechanism.

SOURCE: Systemiq analysis for the ETC.

Ancillary services provide a crucial revenue source for flexibility assets, but these markets can face declining revenue opportunities as more assets participate, particularly in ancillary services due to its inherently small market size. This is showcased in Exhibit 4.5, highlighting the declining revenues from ancillary services in the UK due to market saturation.[256]

Revenue stacking is therefore essential to deploy flexibility assets, and ensuring storage can access multiple revenue streams is key to scaling deployment.

4.2.2 Addressing uncertain and risky revenue streams

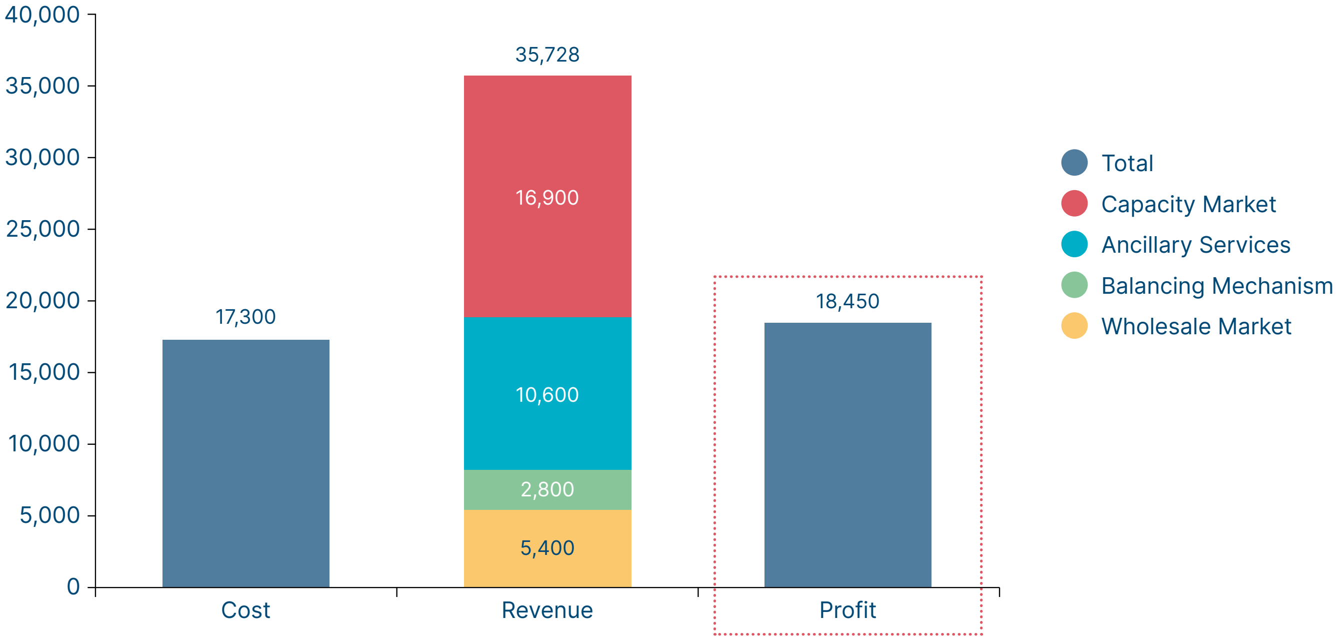
Many of the options available to achieve systems balance described in Chapter 1 will require high upfront capital investments and lengthy payback periods. Some will require lengthy development phases before starting operations and receiving revenue. This is particularly true for longer duration storage projects and long distance HVDC lines. The cost of capital (i.e. required rate of return) will therefore be a key determinant of project economics. If projects are remunerated by participation over time in fluctuating wholesale markets, uncertainty about future revenue streams will increase the cost of capital.

Exhibit 4.6 illustrates the cost, revenue, and profit gap between short duration and medium-to-long duration storage, even when both have access to revenue stacking. This highlights the need for structured funding mechanisms to support long-duration storage, not only due to higher technology costs, but also because current market designs fail to adequately value or incentivise longer-duration flexibility.

Exhibit 4.5

Why access to multiple markets is vital: UK case study showcasing that revenue stacking is necessary to the energy storage business case

UK battery storage with revenue stacking, 2023, 80MW 4-hour battery storage system
($/MWh)



NOTE: We assume an energy storage system using batteries of 80 MW as this is the average size battery storage project in the UK in 2023. The system is sized for 4 hours duration. Other assumptions include; 500 cycles per year, OPEX of $/kWh, 8% annualisation factor, 93% lifecycle efficiency and electricity at $0.06/kWh. For revenue modelling, we also assume that the revenue stack would be 55% frequency response, 5% balancing mechanism, 20% wholesale and 20% capacity market, as per figures from Modo Energy for 2023. We also assume for revenue stacking that the battery would play across all markets; in reality, this would require extensive data and workforce management that make it unlikely. We also assume that the battery would play in both T4 and T1 capacity auctions.

SOURCE: Systemiq analysis for the ETC; BNEF (2025), *2024 Long-Duration Energy Storage Cost Survey Tough Race;* Modo Energy (2024), *December 2024: GB battery energy storage research roundup.*

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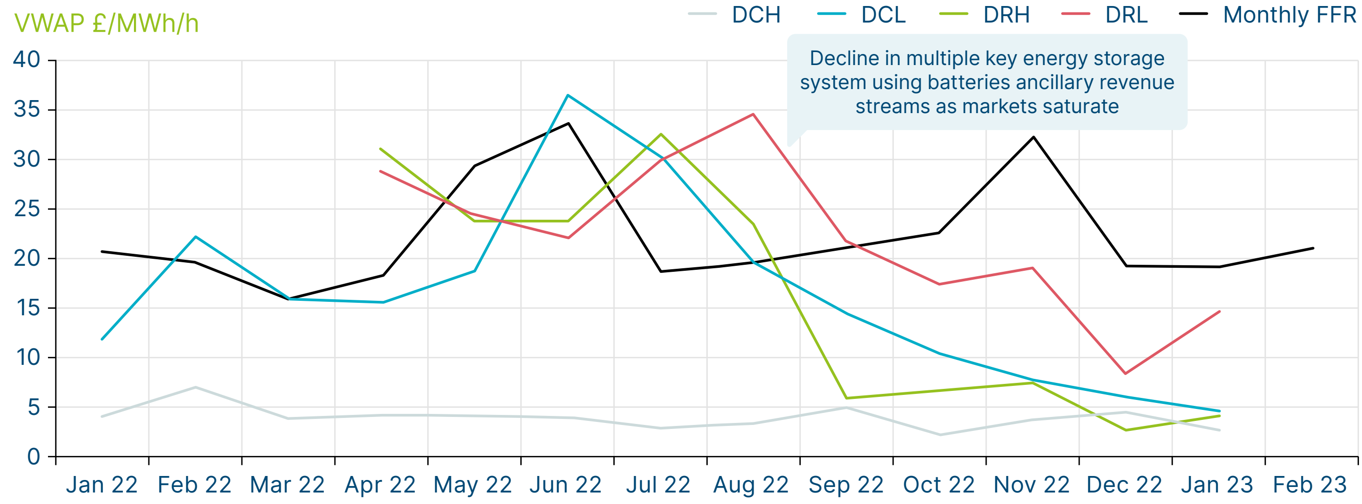
[256] Timera Energy (2023), *Battery investors confront revenue shift in 2023*. Available at https://timera-energy.com/blog/battery-investors-confront-revenue-shift-in-2023/. Accessed May 2025].

Exhibit 4.5

Ancillary services are anticipated to decline due to market saturation

Ancillary services revenue, UK

GW



Decline in multiple key energy storage system using batteries ancillary revenue streams as markets saturate

NOTE: VWAP = Volume-Weighted Average Price, referring to the average price paid per MWh, weighted by the volume of services delivered across each ancillary service. DCH (Dynamic Containment High) and DCL (Dynamic Containment Low) are fast frequency response services designed to manage significant frequency deviations above or below 50 Hz respectively, while DRH (Dynamic Regulation High) and DRL (Dynamic Regulation Low) provide continuous, pre-fault frequency regulation to correct small, persistent over- or under-frequency deviations; Monthly FFR (Firm Frequency Response) is a legacy service procured on a monthly basis to provide frequency balancing, typically slower and now largely superseded by dynamic services as part of National Energy System Operator's (NESO's) transition to a more responsive ancillary services framework.

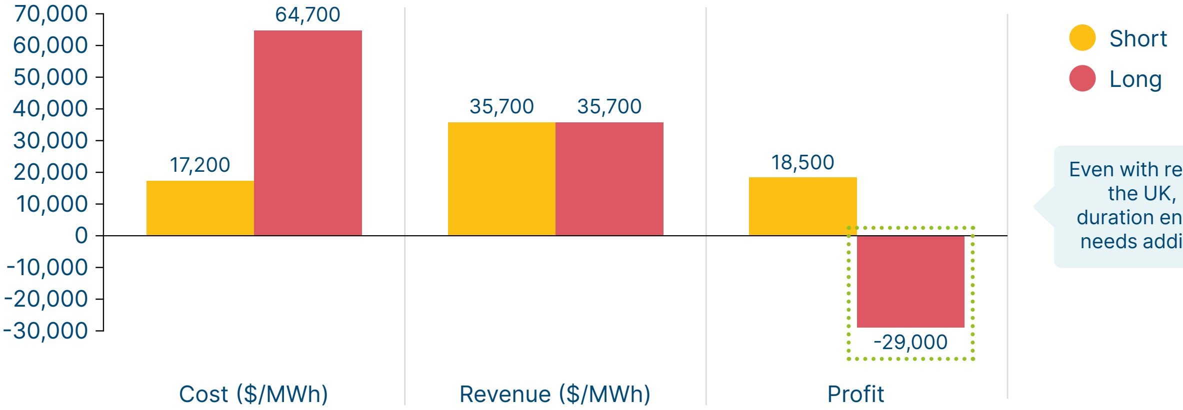
SOURCE: Reused with permission from Timera Energy (2024), *Battery investors confront revenue shift in 2023.* Available at https://timera-energy.com/blog/battery-investors-confront-revenue -shift-in-2023/. [Accessed March 2025].

Exhibit 4.6

Additional revenue support is needed for medium-long duration storage (8-50 hours)

UK short and long-duration energy storage revenue model, 2023

All markets stacked, £/MW



Even with revenue stacking in the UK, medium-long duration energy storage still needs additional de-risking

NOTE: We assume a battery storage of 80 MW as this is the average size energy storage system using batteries project in the UK in 2023. Other assumptions include: 500 cycles per year, OPEX of $/kWh, 8% annualisation factor, 93% lifecycle efficiency and electricity at $0.06/kWh. For revenue modelling, we also assume that the revenue stack would be 55% frequency response, 5% balancing mechanism, 20% wholesale and 20% capacity market, as per figures from Modo Energy for 2023. We also assume for revenue stacking that the battery would play across all markets; in reality, this would require extensive data and workforce management that make it unlikely. We also assume that the battery would play in both T4 and T1 capacity auctions.

SOURCE: Systemiq analysis for the ETC; BNEF (2025), *2024 Long-Duration Energy Storage Cost Survey Tough Race;* Modo Energy (2024), *December 2024: GB battery energy storage research roundup.*

This challenge also existed historically in the development of wind and solar generation projects, and various contract structures emerged to reduce revenue risk by ensuring fixed or partially fixed prices for a share of power generated. These types of contracts will also need to play a role in storage, flexibility and long distance interconnector projects.

In implementing derisking mechanisms, a list of which is shown in Exhibit 4.7, governments and system operators should seek to balance the benefits of revenue certainty (and thus reduced cost of capital) with the benefits of some exposure to market competition. This implies:

- Maintaining some exposure to market prices to encourage technological and business system innovations and short-term operational efficiency.
- Enabling significant competition between different flexibility technologies (e.g., batteries, pumped storage, demand response and interconnectors) while providing adequate support for new technologies in early stages of development.
- Adapting mechanisms as markets mature, for instance, as costs decline and the need for support reduces.

Policies and market structures aimed at reducing revenue uncertainty can involve separate contracts for generation and storage. An alternative approach is to require developers to bid to supply electricity on a round-the-clock basis, bundling together generation sources, storage technologies, and potentially demand side flexibility to meet delivery commitments at the lowest cost. This model, successfully applied in India, shifts the focus from securing revenue for individual inputs (e.g., solar, wind, batteries) to providing certainty for the desired output: reliable, 24/7 electricity. Box I describes India’s successful use of this round-the-clock contracting mechanism.

Exhibit 4.7

Options for de-risked revenue streams for balancing technologies

Level of price intervention ↓

	Definition	Responsible Party	Examples of Deployment
Power Purchase Agreement (PPA)	Long-term contracts where storage assets get paid a fixed price for providing energy or services, improving investment security.	🏢 💡 🏛	🌐 🇪🇺 🇺🇸 🇨🇱 🇬🇧 🇮🇳
Tolls	Payments from grid operators or utilities to storage providers for making capacity available and dispatchable when needed.	⚡ 💡	🇬🇧 🇦🇺 🇺🇸
Cap & Floor Mechanisms	Ensures storage projects earn stable revenues by setting a minimum (floor) and maximum (cap) price.	🏛 📋	🇬🇧 Interconnectors (e.g., Nemo Link)
Feed in tariffs	Fixed payments per unit of stored and discharged energy, ensuring early-stage storage projects receive predictable income.	🏛 📋	🇩🇪 (EEG law) 🇪🇸 (Historically) 🇨🇳

🏢 Corporates 🏛 Government ⚡ Grid Operators 📋 Regulators 💡 Utilities

SOURCE: Systemiq analysis for the ETC.

Box I

Round-the-Clock Contracts in India

India has pioneered the use of round-the-clock (RTC) renewable electricity contracts to provide firm, reliable clean power by bundling solar, wind, and storage into a single procurement. These contracts aim to reduce revenue uncertainty for renewable developers and investors by securing long-term, predictable payments for output delivery, rather than individual inputs.

The Solar Energy Corporation of India (SECI) launched the country's first RTC tender in 2020, awarding 400 MW of contracted capacity to ReNew Power. The bid committed to delivering electricity with at least 80% annual availability, using a combination of solar, wind, and battery storage, at a quoted tariff of IN₹ 2.90/kWh (~US¢3.85 /kWh), with a 3% annual escalation for 15 years, resulting in an effective tariff of IN₹ 3.59/kWh. Since then, there have been five additional RTC auctions, including tenders from SECI and the REMC (Ministry of Railways and RITES joint venture), awarding a total of approximately 6 GW of clean power capacity.[257] Prices initially declined, with SECI's 2021 RTC-II auction clearing at IN₹ 3.01 per kWh (~US¢3.6 per kWh), reflecting early investor confidence and improving integration strategies. However, subsequent auctions, including RTC-IV in 2024 and RTC-V in 2025, saw tariffs rise to between IN₹ 4.25–5.07/kWh (~US¢5.1–5.95/kWh), as developers factored in higher storage requirements, tighter delivery obligations and rising capital costs, highlighting the complexity and value of delivering firm clean power at scale.[258]

Despite this rise, analysis by the Initiative for Energy Change Collaboration (IECC) draws on these auctions to estimate the cost of solar-plus-storage systems capable of delivering 24/7 power at over 95% availability, implying a sub-IN₹ 6 per kWh cost for firm clean electricity in 2024. This is comparable to or below tariffs for new coal plants and current industrial electricity prices in many Indian states.[259] Unlike fossil-based generation, these tariffs offer long-term price certainty, as they are typically fixed for 25 years. This shift presents a cost-effective, inflation-proof alternative for industrial consumers and utilities, while casting doubt on the economic viability of new thermal capacity. This positions India among the global frontrunners in securing low-cost clean energy, alongside China, Australia, and the United States, where renewables plus storage costs have also reached parity or outcompete fossil fuels[260] (including new coal in China[261], and existing coal[262] and gas[263] in the US[264] and Australia[265]).

Key features of India's RTC model include:[266]

- Bundled delivery obligations – instead of separate PPAs for each asset, developers are paid for delivering a firm supply profile.
- Technology neutrality – developers are free to optimise their portfolios using any mix of wind, solar, storage, or other flexibility sources.
- Integration with DISCOMs – power from RTC contracts is sold to India's distribution companies (DISCOMs), often through back-to-back arrangements coordinated by SECI. This structure reduces risk for DISCOMs by providing them with predictable, dispatchable clean energy at competitive tariffs.
- Long-term certainty – contracts typically span 25 years, reducing financing risk and encouraging investment.
- Performance-based incentives – contracts include availability thresholds ranging from 75–85%, with penalties of up to 200% of the tariff for supply shortfalls, incentivising reliable delivery.

The success of these contracts lies in shifting procurement from supporting specific inputs (like solar or batteries alone) to rewarding the outcome the system needs: reliable, affordable, clean electricity delivered 24/7.

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[257] SECI (2024), *Summary of Round-the-Clock Renewable Energy Tenders.*

[258] Renewable Watch (2024), *Ensuring Stable Supply: RTC Renewables and FDREs' Potential to Address Energy Variability.* Available at: https://renewablewatch.in/2024/09/25/ensuring-stable-supply-rtc-renewables-and-fdres-potential-to-address-energy-variability. [Accessed January 2025].

[259] Chojkiewicz et al. (2025), *Implications of India's Solar+Storage Auctions for 24/7 Clean Power.*

[260] Systemiq analysis for the ETC; Bloomberg (2025), *LCOE Data Viewer.*

[261] Carbon Brief (2024), *Guest post: Solar plus batteries 'cheaper than new coal' for meeting China's rising demand.* Available at https://www.carbonbrief.org/guest-post-solar-plus-batteries-cheaper-than-new-coal-for-meeting-chinas-rising-demand/. [Accessed January 2025].

[262] Solomon et al (2023), *Coal Cost Crossover 3.0: Local Renewables Plus Storage Create New Opportunities for Customer Savings and Community Reinvestment.*

[263] Clean Energy Council (2021), *Battery Storage: The new, clean peaker.*

[264] Please note that the reductions in the US were made possible through funding from the Inflation Reduction Act, as highlighted in RMI (2022), *The Business Case for New Gas Is Shrinking.*

[265] Systemiq analysis for the ETC; BNEF (2025), *LCOE Data Viewer.*

[266] Institute for Energy Economics and Financial Analysis (2021), *Understanding Round-the-Clock Renewable Energy Tenders in India.*

4.2.3 Targeted support for new technologies

In addition to de-risked revenue streams, some flexibility assets could also benefit from additional funding to support earlier-stage development. These funding mechanisms are distinct from revenue support mechanisms, covered in the previous section, which provide price certainty once a project is operational. Funding mechanisms instead address earlier-stage barriers, targeting high capital intensity, technology risk or limited track record, which prevent projects from securing financing. Strategic funding should be reserved for technologies that face significant commercialisation barriers, with targeted support for solutions that meet the following criteria:

1. Nascent but necessary technologies – Innovations still in early development that lack a track record of large-scale deployment, such as next-generation grid-forming inverters and novel long-duration storage, but could be critical for future systems.
2. High-CAPEX solutions – Technologies with large upfront costs and long payback periods, making it difficult to secure affordable private financing, such as HVDC interconnectors and flow or air batteries.

To address these challenges, two key funding approaches are recommended, as highlighted in Exhibit 4.8:

1. Short-term deployment support which reduces upfront costs and improves bankability, ensuring first-of-a-kind projects can reach commercial scale. Mechanisms include capital-side support such as tax credits (e.g., U.S. Inflation Reduction Act storage tax credits), subsidies, and grants (e.g., Germany's innovation tenders).
2. Long-term innovation enablers which reduce investment risk and supports later-stage commercialisation to ensure high-impact solutions reach large-scale deployment. Mechanisms include non-revenue-based tools such as loan guarantees (e.g., EU infrastructure loans for interconnectors) and R&D funding (e.g., U.S. Department of Energy grants for long-duration storage).

Exhibit 4.8

Deploying energy storage: learning points from successful short and long duration storage funding programs, vital for their roll-out in nascent markets

Some of the most successful storage programs include:

- California Long duration storage programme & US IRA tax credit
- Germany KfW Scheme
- South Australia's Home Battery Scheme
- Maharastra Solar-plus-storage tenders

Key short-duration programme features include:

- **Long policy duration** – long term commitments with 5-10 years
- Programmes structured to **phase down incentives** over time
- **Clear technology requirements** e.g., specify certain storage durations noted to align with policy goals
- **Geographic targeting** of low adoption regions and zones
- **Mandatory solar pairing** to drive renewable adoption

Key long-duration programme features include:

- Allocating **dedicated multi-year funding** to ensure long-term investment stability
- Technology agnostic and targeting **non-lithium storage technologies** to diversify grid reliability solutions
- Requiring **centralized procurement** to guarantee offtake agreements for developers
- **Integrating competitive bidding** to drive cost reductions and efficiency

SOURCE: Systemiq analysis for the ETC; California Energy Commission (2023), *Long-Duration Energy Storage Program;* KfW Development Bank (2023), *Renewable Energies – Standard (Programme No. 270);* Solar Choice (2024), *South Australia Solar Battery Scheme Explained;* PV magazine (2024), *Maharashtra launches 300MW/600 MWh battery storage tender.*

4.2.4 Locational signals to encourage efficient deployment

As Section 2.3 described, grid investment needs can be reduced by encouraging the optimal location of new generation sources, storage capacity and large scale demands. Location-based wholesale pricing is one mechanism to help achieve this, with other locational signals provided through strategic spatial planning, cost-reflective grid connection charges, and targeted financial incentives that reflect system needs.

Many markets already include some form of locational signals to reflect the proximity of generation to demand centres [see Box J for a case study].[267] Locational marginal pricing (LMP) seeks to do this for wholesale prices by dividing markets into smaller zones, each with its own real-time price. These prices reflect local generation costs, demand variations, and transmission congestion. By providing granular, location-based price signals, LMP can provide efficient operational signals into the market, and can incentivise investment in energy storage and demand side flexibility where grid constraints are most severe. In congested areas, higher and more volatile prices indicate stronger returns for flexibility and new generation. In areas with excess generation, lower prices may encourage energy-intensive businesses to locate there.

There are two categories of LMP - zonal pricing and nodal pricing. Zonal pricing divides the market into regions with distinct prices based on regional supply and demand balances. Nodal pricing assigns prices at individual nodes or connection points in the grid, reflecting local conditions with higher precision. In practice, this means that whilst a market might have many regions, it could have thousands of nodes.

There are many factors to consider regarding the implementation of LMP [Exhibit 4.9]. Implementing LMP requires careful consideration of market design, regulatory frameworks, and investor confidence. While LMP can lead to more efficient dispatch and strategic siting of flexibility resources, it may also introduce market uncertainty due to price volatility and heightened complexity for developers and investors. Therefore, complementary measures such as capacity payments or ancillary service markets are often necessary to stabilise revenues and encourage long-term investments.

Exhibit 4.9

Tradeoffs of Locational Marginal Pricing (LMP) vs. Single Price

	Potential Advantages of LMP	Potential Disadvantages of LMP
Dispatch efficiency & system operation	**Prevents inefficient dispatch and reduces value pool for generation.** Avoids over-compensation of curtailed generation, incentivizing least-cost dispatch.	**May not be needed for optimal dispatch** Other mechanisms can improve dispatch efficiency, but may lack LMP's locational granularity.
Investment signals & system planning	**Encourages flexible generation and storage siting near demand centers;** incentivises demand side flexibility and co-location with generation.	**Investment uncertainty and cost of capital:** Uncertainty around LMP design and pricing zones may disrupt investment decisions and raise the cost of capital, particularly where returns are reduced in surplus generation zones.
Price signals & market design	**More transparent, granular pricing.** Reflects real-time system conditions, improving efficiency.	**May reduce future revenues** for infra-marginal generators if pre-existing assets are located in zones where LMP leads to lower prices, as the system introduces significant price divergence across zones.
Network infrastructure & expansion	**Reduces need for network expansion.** Efficient siting of generation and demand lowers transmission costs.	**Limited ability to respond.** Hard for existing generators, CfD holders, and consumers to relocate.
Implementation & transition challenges		**Long implementation timelines and uncertainty.** A complex transition may delay benefits and create uncertainty around the scale and timing of benefits realised.

SOURCE: Systemiq analysis for the ETC; FTI Consulting and Energy Systems Catapult (2023), *Assessment of locational wholesale electricity market design options in GB.*

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[267] DESNZ (2023), *Electricity market design – evidence from international markets.*

Box J

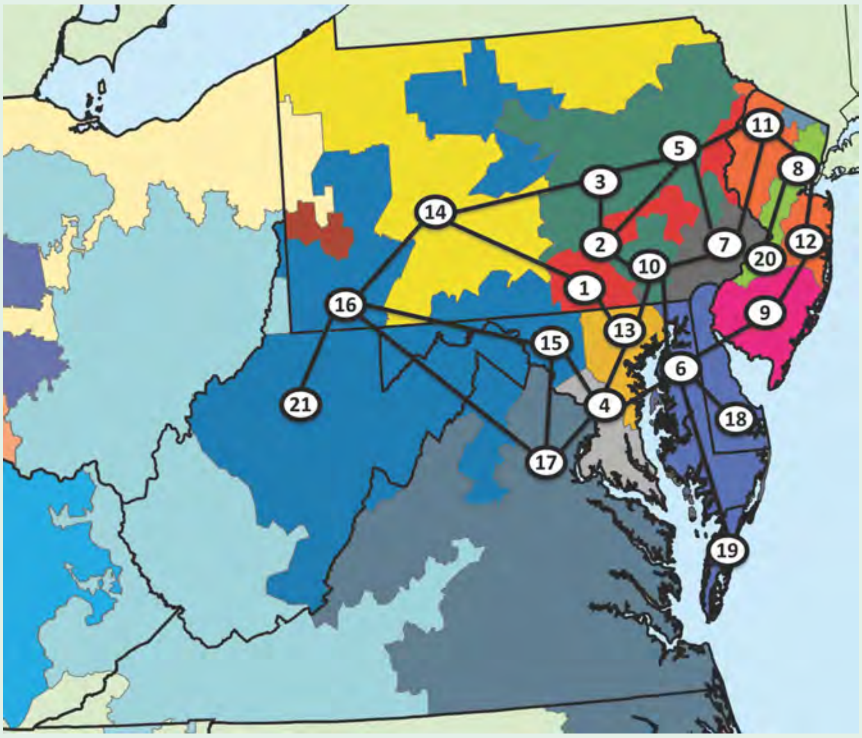
Case Study Example: LMP and Storage Deployment in Pennsylvania-New Jersey-Maryland Interconnection (PJM)

The PJM Interconnection in the United States, one of the largest wholesale electricity markets globally, operates under a locational marginal pricing (LMP) model, which creates greater price variation across different locations compared to single-price markets [Exhibit 4.10].[268] This structure has influenced flexibility investments in several ways:

- Operational Optimisation: LMP increases price volatility by reflecting real-time congestion and local supply-demand imbalances, leading to wider fluctuations in electricity prices than in single-price markets. Storage developers leverage this volatility by charging when LMPs are low and discharging when LMPs spike, allowing for higher arbitrage opportunities than in a uniform pricing system.[269]
- Strategic Siting: Rather than uniformly high-priced congested areas, storage assets are strategically located in areas with high price volatility, where frequent and significant LMP fluctuations allow them to capture greater spreads.[270] This targeted placement improves grid reliability by alleviating local constraints and enhances financial returns.
- Revenue Diversification: While revenue stacking occurs in both LMP and single-price markets, LMP markets provide additional value by amplifying price signals for flexibility assets. Storage projects in PJM not only participate in energy arbitrage but also earn enhanced revenues from capacity payments and ancillary services, as these markets reflect locational price dynamics more accurately.[271] This results in higher revenue potential compared to single-price markets, where uniform pricing can limit these locational incentives.

Exhibit 4.10

PJM Nodes and transmission lines



SOURCE: Re-used with permission from Tanaka, M, Chen, Y and Zhang, D (2018), *On the Effectiveness of Tradable Performance-based Standards.*

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268 Tanaka, M. (2018), *On the Effectiveness of Tradable Performance-based Standards.*

269 Salles, M. B. C., Huang, J., Aziz, M. J., & Hogan, W. W. (2017), *Potential Arbitrage Revenue of Energy Storage Systems in PJM.*

270 DiRenzo, B. (2024), *Navigating PJM's Evolving Battery Storage Landscape.*

271 PJM (2019), *Energy Storage in PJM: A Perspective.*

While LMP has been used in markets like PJM to enable more efficient dispatch of flexibility resources [see Box J and Exhibit 4.10], its applicability varies by market. Some jurisdictions may prioritise alternative approaches, such as capacity mechanisms or targeted grid investments, to enable flexibility deployment in a way that aligns with their specific regulatory and market structures.

In the UK, zonal pricing was formally explored under REMA from April 2022 until the government's Summer Update on 10 July 2025, when it was officially ruled out in favour of retaining a single national wholesale price. Instead, the government will strengthen locational signals through reforms to TNUoS and connection charges, and through spatial planning via NESO's Strategic Spatial Energy Plan, due in 2026. It will also implement targeted operational reforms and expand storage deployment to reduce constraint and curtailment costs, which reached £2.7 billion in 2023 and are projected to rise.[272]

The EU's electricity market operates on a de facto zonal pricing model, where each "bidding zone" has a single wholesale electricity price.[273] In most cases, a country forms a single bidding zone, which supports efficient cross-border trade but fails to reflect internal grid constraints.[274] Some EU countries have adopted more granular zonal pricing. For example, Italy, Sweden, and Denmark have multiple internal zones to reflect structural congestion.[275] Outside of Europe, countries including New Zealand,[276] Singapore,[277] and Chile[278] have also introduced nodal or regional pricing systems.

In summary, LMP is a potential mechanism to enhance grid efficiency by providing location-specific price signals. However, implementation requires careful consideration of market design, including safeguards against market power abuse and unintended cost shifts across regions. The Energy Transitions Commission will publish deeper analysis into locational marginal pricing later in 2025.

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[272] BNEF (2025), *LCOE Data Viewer;* DESNZ (2025), *REMA: Summer Update 2025.*

[273] ACER (2021), *The European Wholesale Electricity Market Design: Main Features and Perspectives.*

[274] European Commission (2023), *Electricity Market Design Reform – Impact Assessment Accompanying the Proposal for a Regulation of the European Parliament and of the Council.*

[275] ENTSO-E (2022), *Bidding Zone Review: Technical Report.*

[276] Electricity Authority of New Zealand (2020), *Review of the New Zealand Wholesale Electricity Market.*

[277] Veolia North America (2024), *Nodal vs Zonal Electricity Markets: What's the Difference and Why It Matters?*

[278] Rudnick, H., Barroso, L., & Mocarquer, S. (2021), *Chile's Electricity Markets: Four Decades on from Their Original Design.*

4.3 Grid regulations to support investment, encourage cost reduction, and speed connection

Chapter 2 outlined the significant investments required in transmission and distribution grids to enable widespread electrification and power sector decarbonisation. It also highlighted the substantial potential to reduce these costs through demand side flexibility, innovative grid technologies (IGT), and optimal siting of generation, storage and new demand.

Enablers relating to optimal location of storage assets were considered in Section 4.2.4, and enablers for demand side flexibility will be considered in Section 4.6. Well-designed regulation and planning rules relating to grid companies are essential to:

- Create incentives for optimal investment in innovative grid technologies.
- Reduce barriers to grid expansion and rapid connection.
- Address legacy issues relating to grid connection fees.

4.3.1 Incentives for investment in innovative grid technologies

As Chapter 2.2 described, there are notable opportunities to reduce required grid investment by deploying multiple variants of innovative grid technologies (IGTs). This would not only reduce costs, but in some cases reduce the need for major new pylon lines or other developments that might face public opposition.

In several countries, however, existing regulation of transmission and distribution companies can dampen the incentive to invest in measures that would lower the capital assets required per kWh delivered. This often occurs when regulation encourages grid operators to minimise operational expenses, while allowing capital investments to be added to the regulatory asset base. These capital costs are then multiplied by an allowed rate of return and passed on to consumers as part of the grid cost.

Regulators should therefore explicitly review and, if necessary, reform approaches to operating and capital cost pass through to increase incentives for IGT deployment.

4.3.2 Connection rules: Addressing backlogs and streamlining processes

Lengthy and opaque grid connection processes are among the biggest constraints to scaling the grid and flexibility technologies discussed in this report. Flexibility assets face complex permitting and approval requirements, often with multi-year delays that erode investment cases and increase system costs. The backlog in connection queues can last up to 14 years in the UK and 7 years in the US. [279,280] Exhibit 4.11 highlights the urgency of reform required in the US. Meanwhile in the UK, the energy regulator Ofgem approved major grid connection reforms in April 2025 aimed at eliminating speculative “zombie” projects and fast-tracking viable clean energy developments, a move expected to reduce connection delays and unlock substantial investment in renewable infrastructure.[281]

Key measures to accelerate grid connections are highlighted in Exhibit 4.12. Each of these measures can play a crucial role in addressing connection delays, but there are implementation considerations to maximise effectiveness:

- **Streamlining permitting and approvals** reduces administrative bottlenecks by requiring regulatory coordination to enforce deadlines and maintain transparency. For example, in the United States, the Federal Energy Regulatory Commission (FERC) introduced Order 2023, requiring grid operators to provide clearer timelines and study processes for new connections, ensuring projects move through the queue more efficiently.[282]
- **Milestone-based queue management** helps prioritise viable projects, but if too rigid, it may inadvertently disadvantage smaller or innovative developers. The UK’s National Energy System Operator (NESO) recently introduced stricter milestone requirements for connection applicants, removing stalled projects from the queue. However, concerns remain that emerging technologies with longer development timelines could face unintended barriers.[283]

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[279] The Guardian (2024). *Renewable energy firms face up to 14-year wait for grid connections in UK.*

[280] The Verge (2024), *US Department of Energy announces $30 million funding to speed up interconnection using AI.*

[281] Ofgem (2025), *Major reforms to grid connection process will speed up delivery of clean energy.*

[282] FERC (2023), *Order No. 2023: Improvements to Generator Interconnection Procedures and Agreements.*

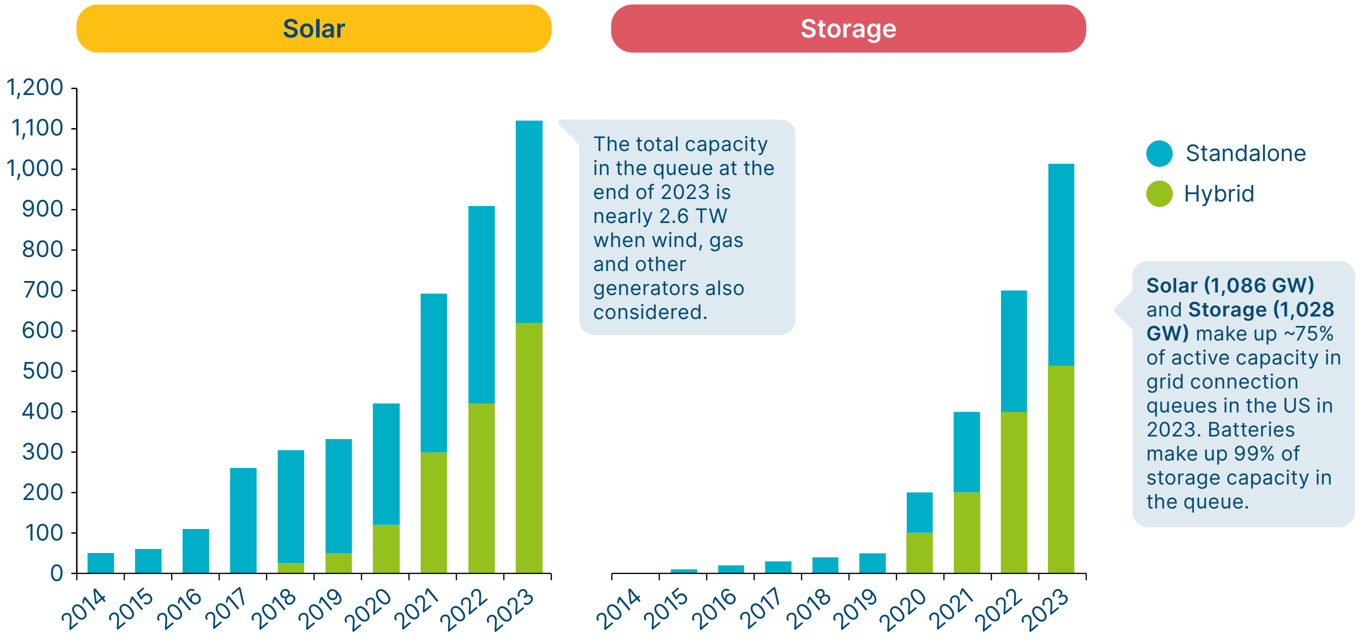
[283] Financial Times (2024), *UK National Grid ESO implements stricter milestone requirements to reduce connection delays.*

Exhibit 4.11

Grid connection queues are a growing bottleneck

Total US capacity in connection queue sizes (2014–2023)

GW



The total capacity in the queue at the end of 2023 is nearly 2.6 TW when wind, gas and other generators also considered.

Solar (1,086 GW) and **Storage (1,028 GW)** make up ~75% of active capacity in grid connection queues in the US in 2023. Batteries make up 99% of storage capacity in the queue.

NOTE: LHS = Solar Power World, RHS = ETC NPV Calculations assuming a project with: CAPEX £150 million, OPEX £3 million, Revenue of £20 million, Project lifetime of 20 years, discount rate of 8% and financing of £6 million. Standalone: Asset not co-located with another technology; operates independently.Hybrid: Co-located assets (e.g. generation and storage) sharing infrastructure or controls.

SOURCE: Energy Markets and Policy, Berkeley Lab (2024), *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection.*

Exhibit 4.12

Actions for reducing grid connection queues

1

Streamlined permitting and approvals

Simplify and expedite the approval process via

- One-stop permitting
- Statutory deadlines
- Integration of digital platforms to manage applications

2

Milestone-based queue management

Quick-fix solution – non-firm grid connections

Projects must meet specific milestones such as:

- Land acquisition
- Permitting
- Financial commitments

Inactive or **zombie** projects are removed or reauctioned

3

Grid modernisation and expansion

Build, upgrade and optimise infrastructure through:

- Strategic investments
- Use of storage to alleviate congestion

SOURCE: Systemiq analysis for the ETC.

- **Grid modernisation and expansion** is essential to reducing connection queues by increasing the physical hosting capacity of the network. Many backlogs stem from transmission or distribution constraints in specific zones, particularly where renewables and storage projects are concentrated. Strategic investments in substations, transformers and line upgrades at these pinch points can unlock stalled projects and enable new flexibility assets to connect more quickly, as discussed in Chapter 2.

While these reforms collectively enhance queue efficiency, their success depends on balancing speed, fairness and cost-effectiveness in execution.

The UK is one example of a market where connection rules have been reformed to address project backlogs and improve queue efficiency. Recent changes introduce stricter project milestones, requiring proof of land ownership, financial commitments, and permitting evidence to prevent speculative projects from delaying grid access.[284] These measures aim to prioritise ready-to-build projects and remove inactive applications, ensuring a more efficient allocation of grid capacity. However, they also introduce additional complexity and higher upfront costs, particularly for smaller developers, highlighting the need for a balanced approach that streamlines connections while maintaining accessibility.

Other countries to enact grid connection reform include:

- Australia: AEMO and the Clean Energy Council are leading the *Connections Reform Initiative*, which aims to streamline the grid connection process by improving project transparency, setting clear milestones, and enhancing coordination between developers and system planners.[285]
- California (CAISO): Implemented queue management reforms that remove inactive or slow-moving projects and introduced deposit requirements to ensure commitment from developers.[286]
- Ireland (EirGrid): Introduced *Enduring Connection Policy (ECP)* rounds, where connection offers are awarded based on project readiness and alignment with grid needs, rather than time of application.[287]
- Germany (BNetzA): Introduced queue management reforms that prioritise projects based on development readiness, such as permitting and financing status rather than application date, to accelerate grid connections and reduce speculative congestion.[288]

4.3.3 Grid fees: Removing legacy barriers

Current grid fee structures often do not adequately account for the unique role of flexibility technologies, such as battery storage and demand side flexibility, leading to inflated costs and market distortions. These fees were originally designed around traditional, one-way electricity flows from large, centralised generators to passive consumers. As a result, many regulatory frameworks treat storage as both a consumer (when charging) and a generator (when discharging), resulting in double charging that significantly erodes the commercial viability of these assets.

Since flexibility and storage technologies don't fit neatly into legacy categories, grid fees often do not adequately reflect their system value, such as congestion relief or balancing support. Countries that have seen early growth in storage, particularly across Europe, have been forced to confront these issues, making grid fee reform a central policy discussion [Exhibit 4.13]. As a result, markets like Italy, Spain, the Netherlands, and Finland have begun introducing exemptions or revised tariffs that better reflect the operational characteristics of flexible assets.

Introducing non-firm (variable) grid access for lower fees is becoming a key solution for flexibility assets, allowing storage and demand side flexibility technologies to connect more quickly while reducing overall system costs. Non-firm grid access refers to a type of grid connection that allows generators to export electricity only when there is available network capacity. Unlike firm access, it does not guarantee uninterrupted use of the grid, as generators can be curtailed during periods of congestion or system constraints. Relying exclusively on 100% firm grid connections represents a legacy barrier that limits the speed and scale of flexibility deployment. In markets such as Denmark, the Netherlands, UK and Australia,[289] non-firm variable grid access models are being introduced to enable faster integration of storage and demand side flexibility without waiting for full network upgrades. This approach not only improves investment signals for flexibility but also optimises network utilisation by ensuring congestion alleviation assets are available where needed most. However, it also introduces business model uncertainty for developers, who must manage the risk of curtailment during periods of congestion or when assets cannot charge or discharge as expected. Solutions are summarised in Exhibit 4.14.

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[284] NESO (2025), *Connections Reform Methodologies – March 2025.*

[285] Clean Energy Council & AEMO (2023), *Connections Reform Initiative: Improving the Grid Connection Experience.*

[286] CAISO (2022), *Interconnection Process Enhancements.*

[287] EirGrid (2021), *Enduring Connection Policy Phase 2 Overview.*

[288] BMWK (2023), *Accelerating Grid Connections for Renewable Energy: Reform of the Connection Queue Process in Germany*.

[289] IEA (2023), *Grid integration of variable renewable energy: Flexibility options and good practices.*

Exhibit 4.13

What are grid fees?

What are grid fees and who imposes them?

- Grid fees (or network tariffs) are charges levied on electricity producers, consumers, and sometimes storage operators for the use of electricity transmission and distribution networks by TSOs and DSOs.

What are the issues with grid fees?

- **Double Charging:** Energy storage systems are often charged grid fees for both consuming (charging) and generating (discharging) electricity, inflating connection and fee costs.
- **Lack of Flexibility Incentives:** Grid fees rarely reward technologies like storage or demand side flexibility for their role in stabilising the grid and integrating renewables.
- **Regional Disparities:** Inconsistent grid fee structures across regions or countries create uneven investment opportunities and market inefficiencies.

SOURCE: Systemiq analysis for the ETC.

Exhibit 4.14

Three main avenues being pursued to solve barriers created by grid fees

Technology classifications	**Categorisation of energy technologies** (e.g., storage, renewables) to **determine their role in the grid and how grid fees are applied,** often defining assets as distinct asset classes.	🇬🇧 🇦🇺
Fee exemptions	**The removal or reduction of grid access or usage fees for specific technologies or services**	🇧🇪 🇩🇪
Tariffs	**Adjustments to grid tariffs to reflect the actual costs and value of technologies in the grid**	🇺🇸 🇦🇺

SOURCE: Systemiq analysis for the ETC.

Case study: The Netherlands

The Netherlands' energy storage sector has been significantly hindered by its grid fee framework, particularly due to double charging and the absence of exemptions available in neighbouring markets. Storage operators must pay for both importing and exporting electricity, leading to some of the highest grid fees in Europe.

- In 2024, grid fees for a 3000 full-load-hour offtake profile in the Netherlands stand at €86.7 per MWh, significantly higher than Germany (€56.5 per MWh), Belgium (€13.9 per MWh), and France (€12.5 per MWh).[290]
- Unlike Germany (where storage and electrolysers are exempt from these fees), or Belgium and France (where storage benefits from reduced charges),[291] Dutch storage developers face limited exemptions, making the country a less attractive investment location for grid-scale batteries and electrolysers.[292]
- TenneT, the Dutch transmission system operator, has implemented temporary 67% reductions through non-firm agreements and time-weighted rates, but these remain interim measures rather than long-term structural reforms.[293]

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[290] Aurora Energy Research (2024), *Grid fee outlook for the Netherlands 2045*.

[291] EASE (2022), *The Way Forward for Energy Storage: Grid Fees Across Europe*.

[292] Energy Storage News (2024), *Netherlands: Non-firm grid connections and lower fees could double BESS deployments.* Available at https://www.energy-storage.news/netherlands-non-firm-grid-connections-and-lower-fees-could-double-bess-deployments/. [Accessed January 2025].

[293] Timera Energy (2024), *Netherlands BESS in focus as grid fees reformed*.

This case study illustrates the competitive disadvantage faced by markets that fail to adapt their tariff structures. Without intervention, markets with high grid fees risk reduced investment, slower flexibility deployment, and higher system costs, as flexibility assets are priced out of the market.

Similar reforms are emerging elsewhere, for example in:

- Germany: Waived double grid fees for battery storage systems to remove barriers to deployment.[294]
- India: Exempted transmission charges for renewable and storage projects commissioned before 2025.[295]
- Chile: Offers reduced grid charges and simplified access for small-scale distributed energy and storage.[296]
- China: Are piloting time-of-use and location-based tariffs to incentivise demand side flexibility.[297]

4.4 Digital tools and AI for more efficient grid management

Power systems with a high share of wind and solar and significant decentralised generation, innovative grid technologies and storage assets will require more active real time management than past systems. Shifting generation and demand profiles will require real time visibility and actions in response to ensure balancing at the multiple durations described in Chapter 1.

Traditional grid operation systems designed around centralised dispatchable generation face challenges in accommodating variable renewables, energy storage, and demand side flexibility. These include operational challenges such as slow responses to grid imbalances, inefficient congestion management and underutilisation of flexibility assets due to lack of visibility,[298] in addition to planning challenges, such as the need for more efficient grid reinforcement.

Two categories of new capability are required:

- Data analytics and AI capabilities to improve system resiliency and optimise grid operations, for example through AI-driven grid forecasting.
- Advanced metering and digitalisation to support storage and flexibility solutions.

4.4.1 Data and AI Modernisation

Effective management of more complex power systems can be enhanced by:

- AI-driven grid forecasting: Machine learning models analyse weather patterns, historical generation trends, and grid congestion data to improve renewable output and demand predictions and reduce curtailment.
- Real-time system monitoring & balancing: AI enhances grid visibility by integrating data from IoT devices, smart meters, and sensors, allowing faster responses to demand fluctuations and supply variability.
- Automated flexibility dispatch: AI optimises battery storage and DSF, ensuring flexibility assets are activated at optimal times to alleviate congestion and balance the grid.
- Grid planning & infrastructure simulation: AI-powered tools enable faster and more detailed scenario modelling, aiding system operators and policymakers in making informed investment decisions for grid expansion.
- Self-diagnosis and grid self-healing: AI enables automatic detection and localisation of faults, allowing rapid isolation and re-routing of power to minimise outages and accelerate system recovery.

A notable example is Google X's Tapestry project, which aims to create an AI-powered, unified platform for grid management.[299] By integrating real-time data and predictive analytics, Tapestry seeks to enhance system resilience and optimise renewable energy integration. In collaboration with Chile's National Electric Coordinator, Tapestry has enabled grid planners to run simulations 86% faster and conduct 30 times as many scenarios simultaneously, facilitating more efficient and accurate grid planning.[300]

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[294] BMWK (Federal Ministry for Economic Affairs and Climate Action) (2023), *Energiewirtschaftsgesetz (EnWG) amendment 2023*.

[295] Ministry of Power, Government of India (2022), *Waiver of ISTS Charges for Renewable Energy and Storage Projects*.

[296] Government of Chile (2022), *Energy Ministry: Distributed Generation Law 2022 (Netbilling Reform)*
Summary: Facilitates small-scale renewables and batteries by reducing upfront charges and simplifying grid access.

[297] NDRC (2023), *Notice on Advancing Time-of-Use and Location-Based Tariff Pilots for Industrial Users*.

[298] ETC (2025), *Demand-side flexibility – unleashing untapped potential for clean power*.

[299] X (formerly Google X) (2024), *Tapestry: AI-Powered Grid Management and Planning*.

[300] Latitude Media (2024), *In Chile, Google X is Taking AI-Powered Grid Tools Out of Pilot Purgatory*.

4.4.2 Advanced metering and digitalisation

Bringing more grid and flexibility technologies onto power systems requires real-time data, dynamic system optimisation, and automated control mechanisms. Advanced Metering Infrastructure (AMI) and digitalisation are essential in enabling greater market participation of energy storage, demand side flexibility, and other grid-supporting technologies by improving data visibility, market integration, and operational efficiency. In parallel, advanced automation and control technologies for grid assets are becoming critical to enable real-time optimisation and system-wide coordination. Examples include National Grid's Pathfinder projects and advanced substation automation trials.[301]

The deployment of smart meters, sensors, and digital control systems, including remotely controllable assets such as transformers and switchgears, enhances the ability of grid operators, aggregators, and consumers to respond to grid conditions in real time. Key benefits include:

- Optimised demand side flexibility: AMI enables automated, price-responsive energy consumption, allowing storage, electric vehicles, and smart appliances, such as heat pumps, electric water heaters, and smart thermostats, to shift demand away from peak periods, alleviating congestion and reducing system costs.[302]
- Increased visibility for grid operators: Digitalisation provides granular data on energy flows, supporting real-time forecasting and allowing more effective integration of flexibility resources such as battery storage and virtual power plants.
- Grid resilience and predictive maintenance: AI-driven monitoring detects grid congestion and predicts equipment failures before they occur, reducing downtime and improving the reliability of grid assets.

To fully integrate storage and demand side flexibility, power systems must accelerate the deployment of smart meters and AI-driven forecasting tools. By providing real-time visibility, automated control, and market access, these technologies enable faster deployment and more effective utilisation of flexibility resources, supporting the transition to a resilient, low-carbon energy system.

Despite the clear potential of AI and digital technologies to improve grid efficiency and flexibility, regulatory and commercial frameworks have not kept pace with innovation. A key barrier is the high upfront cost of deploying advanced metering infrastructure, sensors, and AI systems, combined with uncertain or long-term payback periods. This cost-benefit mismatch is especially challenging in regulated environments where savings may accrue to the system, but the investment risk is borne by utilities or third-party providers. In many cases, existing regulatory structures do not recognise or reward the system value of data-driven flexibility, creating weak incentives for deployment.

To overcome this, regulatory frameworks should evolve to explicitly value the role of digital and AI-based tools in delivering flexibility and system optimisation. This could include allowing digital solutions to participate in flexibility markets, providing upfront support or incentives for enabling infrastructure (such as AMI), and adjusting cost recovery models to better reflect whole-system benefits. Such reforms are essential to accelerate the integration of smart grid technologies and unlock their potential to support a more dynamic, low-carbon power system.

4.5 Addressing supply chain and workforce constraints

The large scale investment needed in transmission and distribution grids (as discussed in Chapter 2) and in the multiple forms of the grid and flexibility technologies described in Chapter 1, could be constrained by bottlenecks in either:

- Supply chains for specific equipment or installation capability.
- The skilled workforce required.

4.5.1 Potential supply chain bottlenecks and actions to overcome

The ETC has previously assessed supply chain vulnerabilities across various parts of the energy transition. These include:

- Minerals and materials supply in our 2023 report *Material and Resource Requirements for the Energy Transition.*
- Supply chains in the 2023 report *Better, Faster, Cleaner: Securing clean energy technology supply chains.*

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[301] National Grid (2024), *Advanced Automation and Control Technology for Efficient Grid Operation (Project: NIA2_NGET0033).*

[302] ETC (2025), *Achieving Zero-Carbon Buildings: Electric, Efficient and Flexible.*

- Supply chains specifically related to the offshore wind industry in the 2024 report *Overcoming Turbulence in the Offshore Wind Sector*.

This report builds on those insights by evaluating supply chain risks specific to the balancing and grid technologies that underpin the development of clean, reliable power systems.

The need for a resilient supply chain across these technologies is critical. As explored in Chapters 1 and 2, modernising and expanding electricity grids and deploying grid and flexibility assets at scale, both in front of and behind the meter, is central to the transition. Demand for essential equipment is rising across power, digital, transport, and industrial sectors, intensifying pressure on already stretched global supply chains for transformers, cables, power electronics, storage systems, and generation technologies.

Moreover, supply chain constraints are no longer a distant risk; they are already impacting project timelines and investment decisions. Some critical components, including HVDC cables and large power transformers, face lead times of up to five years, with a limited number of manufacturers able to supply global demand.[303] In parallel, battery energy storage systems are available at falling prices, supported by significant overcapacity in China, but this geographic concentration poses a risk to resilience and energy security.[304] The simultaneous increase in demand across multiple geographies and sectors means that even where global capacity appears sufficient, delivery bottlenecks may still emerge.

To anticipate and mitigate these risks, we have assessed the underlying components of the key technologies discussed in this report to identify where supply chain vulnerabilities are most severe. From this analysis, we identified four technologies or components that are particularly exposed. These were selected because they face the highest combined risks across three dimensions highlighted in earlier ETC reports:[305]

- Bottlenecks caused by a structural imbalance between demand and manufacturing capacity.
- High geographic or corporate concentration in supply.
- Environmental or social concerns associated with production.

They are also required at significant scale to meet system needs this decade, and delays in their delivery would materially constrain system buildout. These key technologies and their relating supply chain risks include:

1. Transformers, including large power and distribution transformers

Transformers, both large power and distribution class, are experiencing acute strain. Prices have more than doubled in real terms compared to pre-pandemic levels, and average delivery lead times have nearly doubled.[306] Manufacturing capacity is capital-intensive and slow to scale, due to constraints on key inputs like grain-oriented electrical steel.[307]

2. Cables and HVDC systems

HVDC systems and high-voltage cables face rising demand, with lead times of 2–3 years and converter orders stretching to 2029,[308] while new manufacturing capacity can take three to four years to come online.[309] This lag is already creating delivery backlogs, with converter station orders from major suppliers such as Hitachi Energy and Siemens Energy now stretching into 2028–2029.[310] These challenges are reflected in price trends, as shown above in Exhibit 4.15. This sharp increase underscores the growing mismatch between short-term availability and rapidly rising global demand, particularly for cables required in HVDC transmission, offshore wind, and interconnector projects.

3. Gas Turbines

Gas turbines, which will be critical for providing ultra-long duration balancing via several routes (as discussed in Section 1.5.5) also face significant constraints. Global manufacturers such as GE Vernova and Siemens Energy report order books extending to 2029 or beyond.[311] This reflects supply chain disruptions, rising peaking demand,

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[303] Inverto (2024), *Navigating the Power Cable Supply Crunch*.

[304] Utility Dive (2024), *Battery Oversupply and Falling Prices Are Driving a Global Energy Storage Boom*.

[305] ETC (2023), *Better, Faster, Cleaner: Securing Clean Energy Technology Supply Chains*.

[306] IEA (2024), *Building the Future Transmission Grid*.

[307] Fastmarkets (2024), *Powering the Energy Transition: Supply Shortage of Electrical Steel Could Crimp Energy Transition Movement*.

[308] IEA (2024), *Building the Future Transmission Grid*.

[309] Ibid.

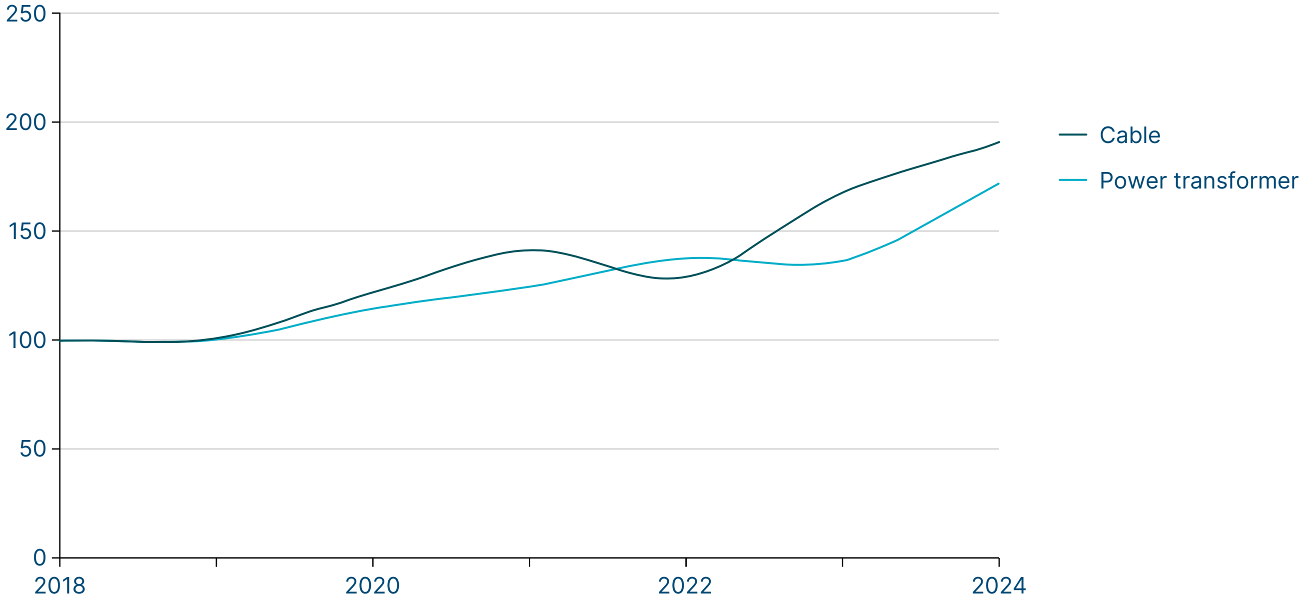
[310] Power Technology (2024), *Innovators in HVDC Transmission Systems for the Power Industry*.

[311] Power Magazine (2024), *Gas Power's Boom Sparks a Turbine Supply Crunch*. Available at https://www.powermag.com/gas-powers-boom-sparks-a-turbine-supply-crunch/. [Accessed January 2025].

Exhibit 4.15

Rapid price escalation in transformers and cables signals growing strain on grid component supply chains

Power transformer and cables price index in real terms (2018 USD), 2018–2024
Price index (2018 USD)



SOURCE: IEA (2024); *Building the Future Transmission Grid,* https://www.iea.org/reports/building-the-future-transmission-grid, License: CC BY 4.0.

and underinvestment linked to market uncertainty.[312] In the near term, any additional demand, whether from clean hydrogen-fired turbines or conventional peakers, risks colliding with these existing constraints. This underscores the importance of improving supply chain resilience and ensuring access where gas is genuinely needed, but it should not be misinterpreted as a case for large-scale gas buildout. As set out in Section 1.5.5, gas use should be tightly ringfenced to ultra-long duration balancing needs where it is clearly the most cost-effective option.

4. Energy Storage Systems, with Lithium-ion Batteries

Energy storage systems with lithium-ion batteries are integrated systems designed to store electrical energy in chemical form and release it when needed to support grid flexibility, reliability, and balancing. BESS Energy storage systems with lithium-ion batteries comprise of cells plus associated hardware, software, and infrastructure, each with distinct supply chain and geopolitical risks. While global manufacturing capacity has grown rapidly and prices have fallen, more than 75% of global battery cell production remains concentrated in China.[313] This exposes the sector to geopolitical risk, potential trade barriers, and disruption from localised shocks. These risks are especially pronounced for chemistries such as lithium iron phosphate (LFP) and emerging sodium-ion batteries, where China is particularly dominant.[314]

In light of these risks, power system development strategies must include robust planning to ensure secure and timely supply of critical technologies. Four priority actions can reduce exposure to bottlenecks and enable smoother system buildout.

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[312] Power Engineering (2025), *Long lead times are dooming some proposed gas plant projects.* Available at https://www.power-eng.com/gas/turbines/long-lead-times-are-dooming-some-proposed-gas-plant-projects/. [Accessed May 2025].

[313] IEA (2024), *The Battery Industry Has Entered a New Phase.*

[314] New York Times (2023), *Why China Could Dominate the Next Big Advance in Batteries.* Available at https://www.nytimes.com/2023/04/12/business/china-sodium-batteries.html. [Accessed January 2025].

1. Strategic supply chain planning

Strategic supply chain planning must begin with a shared, long-term vision across governments, businesses, and regulators, aligning with the "Strategic Vision & Planning" pillar discussed at the start of this chapter. Comprehensive, forward-looking planning is essential to ensure the secure and timely supply of critical technologies and forms the foundation for all subsequent policy actions.

For supply chains, effective planning includes:

- Clearer visibility on long-term demand, with clear and credible demand signals enabling manufacturers to invest confidently in expanding production of long-lead components such as transformers, HVDC cables, and gas turbines
- National transmission system development plans, such as those being advanced with the UK's Centralised Strategic Network Plan[315] and Denmark's Long-Term Offshore Wind Buildout Plan,[316] should include transparent buildout timelines for specific technologies, including projected volumes of cables, converter stations, storage capacity, and transformer units
- Publicly endorsed and regularly updated investment plans, aligned with national decarbonisation targets, can reduce investment risk for suppliers. As highlighted in *Better, Faster, Cleaner,*[317] anticipatory market-making is essential in nascent or constrained supply chains, particularly where lead times exceed project development cycles

2. Targeted actions to tackle visible bottlenecks

Once strategic planning is in place, targeted interventions can be implemented to address specific bottlenecks in both the short and long term.

- In the short term, targeted actions must ease immediate supply pressures. Reconditioning transformers and repurposing EV batteries can enhance supply and reduce environmental impact.[318,319] These approaches offer near-term relief without requiring major manufacturing ramp-ups.
- Long-term procurement mechanisms must address structural imbalances between demand and capacity. Tools such as advance purchase agreements, framework contracts, and capacity reservation agreements can provide manufacturers with the confidence to invest in expanding production capacity ahead of firm project-level demand.
- To complement national planning efforts, addressing geographic concentration in key components - such as battery cells, large transformers, and power electronics, could be important where it is seen to impact competitiveness and energy security. Governments could support regional manufacturing through investment incentives. Optimal ways to do this are discussed in the ETC's report *Global trade and energy transition; Principles for clean energy supply chains and carbon pricing*, published in June 2025.[320]

3. Strengthen collaboration across stakeholders

Effective coordination among governments, Transmission System Operators (TSOs), developers, manufacturers, and regulators is crucial to anticipate demand surges and mitigate supply chain risks across grid and balancing technologies.

- Structured engagement can improve visibility of supply chain needs and align procurement cycles to reduce delays. In Germany, TSOs have pursued joint procurement of HVDC components to secure limited manufacturing slots, while the EU's Joint Purchasing Platform is being considered as a model for aggregated purchasing of critical inputs.[321]
- Beyond procurement, collaboration helps synchronise system buildout timelines. In the UK, the creation of the National Energy System Operator (NESO) is intended to deliver whole-system planning across electricity and gas infrastructure, enabling more integrated decisions on where and when to deploy generation, transmission, storage and flexibility assets.[322]
- Better sequencing of project delivery and infrastructure deployment, enabled by early engagement and whole-system coordination, will be critical to avoid bottlenecks for technologies with long lead times.[323]

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[315] NESO (2024), *Centralised Strategic Network Plan.*

[316] State of Green (2025), *Denmark unveils new plans to boost offshore wind and hydrogen infrastructure.*

[317] ETC (2023), *Better, Faster, Cleaner: Securing Clean Energy Technology Supply Chains.*

[318] Ibid

[319] ETC (2023), *Material and Resource Requirements for the Energy Transition.*

[320] ETC (2025), *Global Trade in the Energy Transition: Principles for Clean Energy Supply Chains and Carbon Pricing.*

[321] European Commission (2024), *Joint Purchasing Mechanism for Strategic Raw Materials.*

[322] UK Government (2023), *Energy Act 2023.*

[323] ETC (2023), *Better, Faster, Cleaner: Securing Clean Energy Technology Supply Chains.*

4.5.2 Workforce challenges and solutions

Rapid deployment of grid flexibility technologies requires a highly skilled workforce, but shortages in key roles and long training lead times could slow progress. Workforce strategies must be scaled up now to meet future energy transition demands.

Many critical grid roles, such as line workers, power engineers and technicians, require extensive training, with some positions taking up to seven years to qualify. Additionally, the evolving nature of power systems demands new digital skills in automation, AI-driven grid management, and cybersecurity. Without targeted workforce development, the expansion of grid and flexibility solutions will face significant delays.

Leading solutions:

- **Advanced training programs:** Governments and industry stakeholders should expand vocational training and apprenticeship schemes to fast-track skilled labor development. To meet the UK's clean energy targets by 2030, the government and industry stakeholders are collaborating to train a "clean power army" through expanded vocational training and apprenticeship schemes. For instance, National Grid plans to support around 55,000 additional jobs by the end of the decade,[324] while Scottish Power's SP Energy Networks aims to double its transmission workforce, creating approximately 1,400 jobs and supporting a further 11,000 across the UK.[325]
- **Industry-academia collaboration:** Aligning energy sector needs with education programs ensures a steady pipeline of skilled professionals. Germany's dual vocational training system exemplifies effective collaboration between industry and academia, integrating classroom education with real-world training. This model ensures that apprentices acquire both theoretical knowledge and industry-relevant skills, contributing to a stable and skilled workforce in the energy sector.[326]
- **Continuous upskilling and knowledge transfer:** Ongoing training programs should focus on reskilling existing workers for emerging grid technologies. National Grid's 'Grid for Good' program in the UK provides technical training in smart grid technologies to meet future workforce needs.[327]

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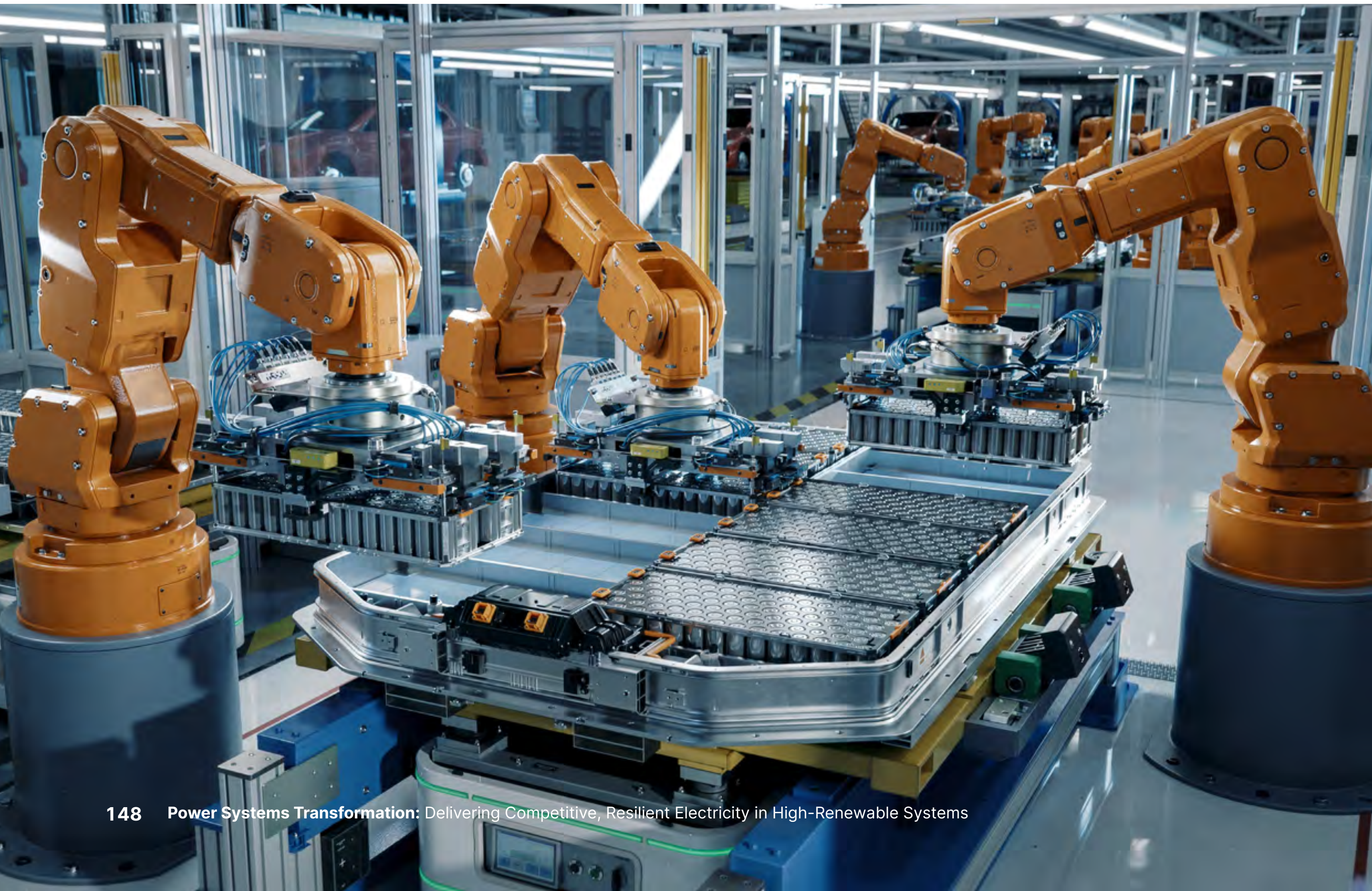
[324] National Grid (2024), *The Great Grid Update.* Available at https://www.nationalgrid.com/the-great-grid-upgrade. [Accessed January 2025].

[325] UK Government (2025), *Government and industry to train up 'clean power army'.* Available at https://www.gov.uk/government/news/government-and-industry-to-train-up-clean-power-army. [Accessed May 2025].

[326] Shergill, P. (2025), *Insights from Germany's Dual Apprenticeship Model & Industry Collaboration*, LinkedIn. Available at: https://www.linkedin.com/pulse/insights-from-germanys-dual-apprenticeship-model-prithvi-shergill-pr1oc. [Accessed May 2025].

[327] National Grid (2025), *What is Grid for Good?* Available at https://www.nationalgrid.com/responsibility/community/grid-for-good. [Accessed May 2025].



4.6 Consumer engagement and product design to enable demand side flexibility

Chapter 1 Section 3.1 described the major role that demand side flexibility could play in meeting the short duration balancing challenge with less investment in storage. In addition Chapter 2 Section 2.1 described how demand side flexibility can help in reducing the need for additional distribution grid investment.

Seizing this potential will require building consumer trust in demand side flexibility technologies and offering well-designed products that encourage engagement and adoption.

Building consumer trust in demand side flexibility technologies

Demand-side flexibility has the potential to engage a broad range of energy users, from large industrial sites to individual households. However, uptake remains uneven due to limited familiarity. Technologies and processes to modulate energy consumption, or to deploy behind-the-meter storage solutions can appear complex, opaque, or intrusive, particularly for residential users, leading to hesitation in adoption and participation.

This lack of familiarity does not always reflect active distrust, but it highlights a knowledge gap that must be addressed. Commercial and industrial users, for example, may hesitate to invest in battery storage or participate in flexibility markets due to perceived complexity, excessive risk perceptions, or unclear returns, while residential consumers may worry about impacts on comfort, privacy, or bills.

To build trust, energy retailers and service providers must:

- Invest in consumer education, highlighting how flexibility delivers cost savings, emissions reductions, and improved resilience. For instance, the UK's Demand Flexibility Service engaged 1.6 million households through clear financial incentives and communications.[328]
- Ensure transparency and user control, so consumers understand how automated systems work and can adjust settings to reflect personal or operational preferences. Smart EV charging and heat pump controls should avoid one-size-fits-all approaches, as different users have different comfort, cost, and scheduling preferences. Flexibility technologies that do not accommodate these can lead to frustration, low engagement, and reduced effectiveness..
- Guarantee strong data privacy protections, including transparent governance, robust cybersecurity, and clear consent protocols to reassure users that their real-time energy data is secure and used to their benefit.

By addressing these concerns and raising awareness, stakeholders can lay the groundwork for confident consumer participation in the energy transition.

Attractive products and services to enable DSF

Once awareness and trust are established, the next challenge is to design systems that enable consumers – both commercial & industrial as well as individuals - to engage easily, confidently, and at scale. Strengthening engagement means reducing friction, offering clear incentives, and ensuring technologies are tailored to user needs.

Key enablers of consumer engagement by energy retailers and service providers, including operators of virtual power plants (VPPs) and aggregators, include:

- Seamless automation, minimising the need for manual control while allowing consumers to set boundaries and preferences.
- Interoperability, ensuring flexibility assets, such as batteries, heat pumps, or EVs, can be easily integrated and controlled backed by resilient digital infrastructure, including smart meter communications and shared digital platforms for data access and control.
- Transparency, so users understand how their participation affects both their bills and the wider system.

Case studies highlight how retailers and service providers are already building trust with consumers through the use of well-designed demand side flexibility technologies. For example, Octopus Energy's Kraken platform uses AI to optimise energy use across connected home devices. In its 2022 Saving Sessions, over 200,000 UK households

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[328] National Grid ESO (2023), *Demand Flexibility Service: Consumer Engagement Report*. Available at: *https://www.nationalgrideso.com/document/286991/download*

reduced peak electricity demand by 108 MW, with minimal manual intervention.[329] These kinds of frictionless, rewarding participation models demonstrate the potential for rapid scaling.

Beyond the household level, innovative models and systems are emerging to coordinate distributed energy assets, such as rooftop solar, batteries, and smart appliances, at the neighbourhood or district scale. This involves coordination, or leadership from, local and national government that will need to drive the introduction of products and services to encourage the development of DSF.

Some of the key areas of service deployment include local flexibility markets (typically operated by DSOs), smart local energy systems (SLES), led by local authorities or community energy groups, which integrate local generation, storage, flexible demand, and digital controls to optimise local energy use and reduce grid reliance; and initiatives like District Self-Balancing (DSB), currently being trialled by Energy Systems Catapult and partners, which enable aggregators to coordinate behind-the-meter assets to ease local congestion and support system operation. For instance, the Caldicot project in the UK tested a self-balancing virtual private network integrating local solar generation, battery storage, and district heating, allowing consumers to trade demand flexibility to balance the local energy network.[330] Similarly, DSB schemes have been proposed as scalable solutions to manage local congestion and defer costly grid infrastructure upgrades.[331] Ensuring these services can thrive will require stronger institutional support. For example, in the UK, there have been suggestions that the creation of a central Flexibility Delivery Unit would help coordinate local and national actions, in addition to a system-level governance model with shared metrics to monitor progress and enable more consistent delivery across stakeholders.[332]

Local and national governments play a critical role in enabling demand side flexibility through coherent policy, investment, and coordination. Key enablers of consumer engagement by local and national government include:

- Clear national policy frameworks and roadmaps to define the role of demand side flexibility in achieving decarbonisation, system reliability, and affordability goals.[333]
- Targeted public investment and incentives, particularly to scale digital infrastructure, enable market participation, and de-risk innovation[334]
- Local delivery coordination, including support for regional demand side flexibility pilots, integration of demand side flexibility into area-based planning, and shared platforms for grid and local actors.
- Integration of demand side flexibility into procurement and planning standards, embedding flexibility into public sector procurement, distribution network reinforcement decisions, and local area energy planning
- Robust consumer protection and data governance standards, ensuring fair access, transparency, and trust in demand side flexibility services and platforms[335]

When effectively designed, these approaches can maximise the local use of clean electricity, reduce strain on distribution grids, and open new participation pathways for prosumers, offering value not just through individual savings, but through their contribution to system-wide efficiency and resilience. Notably, demand side flexibility technologies and services are gaining traction across a wide range of global markets and show potential to benefit consumers in diverse regulatory and economic contexts.

For example, emerging markets are piloting innovative models to enable flexible demand:

- **India** is rolling out smart meters nationwide, creating the infrastructure for time-of-use pricing and responsive demand.[336]
- **Kenya** is exploring demandside management and smartgrid strategies to address peak load and reduce outages.[337]
- **Nigeria** is scaling pay-as-you-go solar-plus-storage systems, helping consumers manage load and costs – early steps toward full flexibility integration.[338]

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[329] Octopus Energy (2022), *Believe it or watt: Octopus Energy customers provide 108MW of grid flexibility in first Saving Session.*

[330] UK Research and Innovation (2022), *Smart Local Energy Systems: The Energy Revolution Takes Shape.* Available at: *https://www.ukri.org/wp-content/uploads/2022/01/UKRI-250122-SmartLocalEnergySystemsEnergyRevolutionTakesShape.pdf*

[331] Smart Energy Europe (2023), *District Self-Balancing: A Scalable Solution for Local Grid Management.* Available at: *https://smarten.eu/wp-content/uploads/2023/08/District-Self-Balancing_08-2023_DIGITAL.pdf*

[332] Innovation Zero World Congress (2025), *Scaling flexible, consumer-led grids.*

[333] Innovation Zero World Congress (2025), *Scaling flexible, consumer-led grids.*

[334] Innovation Zero World Congress (2025), *Scaling flexible, consumer-led grids.*

[335] Innovation Zero World Congress (2025), *Scaling flexible, consumer-led grids.*

[336] Government of India (2023), *National Smart Metering Programme Dashboard*

[337] Kiprop et al. (2019), *Demand Side Management Opportunities in Meeting Energy Demand in Kenya.*

[338] Odunfa & Ogunbiyi (2022), *Scaling Pay-As-You-Go Solar in Nigeria, RMI Insight Brief*

These examples show that with the right digital tools, incentives, and system design, consumers everywhere can become active participants in the energy transition.

Exhibit 4.18 below illustrates key solutions to drive consumer engagement, which can be pursued by utilities, service providers and government. Also included are case studies to highlight where this is already taking place.

Exhibit 4.18

Consumer engagement solutions across storage and flexibility technologies to improve grid efficiency

	Solution		Case Study
1	Consumer awareness educational programs: build foundational understanding of flexibility technologies, dynamic tariffs, and participation benefits.	1	**UK:** Demand Flexibility Service educated households on energy savings, reducing 3,300 MWh during peak times.
2	Create financial incentives: rebates, grants, and dynamic pricing models to make technologies accessible and appealing.	2	**Germany:** Incentives for large industrial consumers to adopt demand-side flexibility solutions.
3	Deploy smart technologies and advanced energy management systems: facilitate participation through automation and real-time optimisation tools.	3	**California:** Automated demand response programs use smart appliances to engage consumers in energy storage and demand shifting.
4	Invest in low-cost smart meter and IoT device rollouts: enable consumer interaction and responsiveness via affordable infrastructure.	4	**India:** National Smart Grid Mission installed over 4 million smart meters in urban areas.
5	Anticipatory training of local communities: build familiarity and trust through hands-on, community-level engagement projects.	5	**Vietnam:** Battery Storage for Renewable Energy Integration Program trains local operators to deploy residential energy storage.
6	Global knowledge transfer: share international best practice to support tailored national and local approaches.	6	**Kenya:** Power Demand Response Program educates consumers on shifting electricity usage during peak hours.

SOURCE: Systemiq analysis for the ETC; National Grid ESO (2023), *Demand Flexibility Service: Winter 2022/23 Case Study;* Energy-UK (2023), *Demand Flexibility Service engaged 1.6 million households and delivered 3.3 GWh of savings;* California Energy Commission (2023), *Load Flexibility: Automated demand response programs with smart appliance integration;* Federal Ministry for Economic Affairs and Climate Action, Germany (2021), *Energy Efficiency Strategy for Industry;* India Ministry of Power (2023), *National Smart Grid Mission Dashboard;* GIZ (2022), *Battery Storage for Renewable Energy Integration in Vietnam;* Power Africa (2020), *Kenya Power Demand Response Pilot Program.*

Consumer engagement is central to the success of a breadth of grid and flexibility technologies, including energy storage, innovative grid technologies, and most importantly, demand side flexibility. Ensuring transparency, financial viability, and ease of participation will drive broader adoption, supporting grid stability, decarbonisation, and cost efficiency.


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