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Integration of variable renewables in the energy system of the EU and China

Policy Considerations

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EU-China Energy Cooperation Platform was launched on 15 May 2019, to support the implementation of activities announced in the "Joint Statement on the Implementation of EU-China Energy Cooperation". The overall objective of ECECP is to enhance EU-China cooperation on energy. In line with the EU's Green Deal, Energy Union, the Clean Energy for All European initiative, the Paris Agreement on Climate Change and the EU's Global Strategy, this enhanced cooperation will help increase mutual trust and understanding between EU and China and contribute to a global transition towards clean energy on the basis of a common vision of a sustainable, reliable and secure energy system. ECECP is implemented by a consortium led by ICF, jointly with Energy Research Institute of National Development and Reform Commission and China Energy Conservation and Environment Protection Consulting; policy steering is by the EU (DG ENER) and the China National Energy Administration.

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FOREWORDS

China and the European Union have many things in common, many challenges to discuss together, and many good practices to share. This is particularly the case in the power sector; China leads the world in its investments into renewables generation capacity, and as the leading manufacturer of PV panels. The EU has also made enormous strides in achieving a rapid growth in installed renewables capacity, and as the main producer of wind turbines, particularly offshore.

The two reports presented here look at the global picture from two angles: the use of markets to give new impetus to the power sector while guaranteeing security of supply; and the integration of an increasing amount of renewables into the power sector and the markets.

The formation and implementation of markets in the power sector is a challenge, and a complex task in giant territories like China, with about 30 different provinces, and the EU, with its 27 member states. Inevitably markets operate at different levels (nationally and locally). The power sector, by its very nature, also requires a 'sequence of successive markets' (from months ahead, to day-ahead, intra-day and spot markets). Consequently, extensive territories end up with a sequence of successive markets that operates on two levels. Decisions at each level must, in one way or another, be linked with the physical management of power flows through the grids and the system.

This is what is known as the 'market design' issue. How does China approach it, and what is its rationale? How and why does-it differ from the EU? Do China and the EU have the same goals while using the same tools, or the same tools when addressing the same goals?

The same questions arise when power systems and markets are required to absorb an increasing proportion of renewables. Solar and wind generation require very high fixed-cost investments upfront and their output fluctuates. How are the existing market sequences responding to renewables in China and the EU? How should market outcomes connect with the new needs of the power system in the face of intermittent output? Where should new practices be concentrated – nationally, or locally? And where in the market sequence should those new practices be introduced? How will they affect the day-to-day management of power flows?

These questions lead inexorably to a further question: are the challenges posed by renewables mainly operational (how to adapt within the existing power system), or mainly infrastructural (how to invest to redefine the structures of the existing sector)?

Read the reports, and you will know all. May friendly cooperation between China and the EU long continue!

Jean-Michel Glachant

Director of Florence School of Regulation

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EXECUTIVE SUMMARY

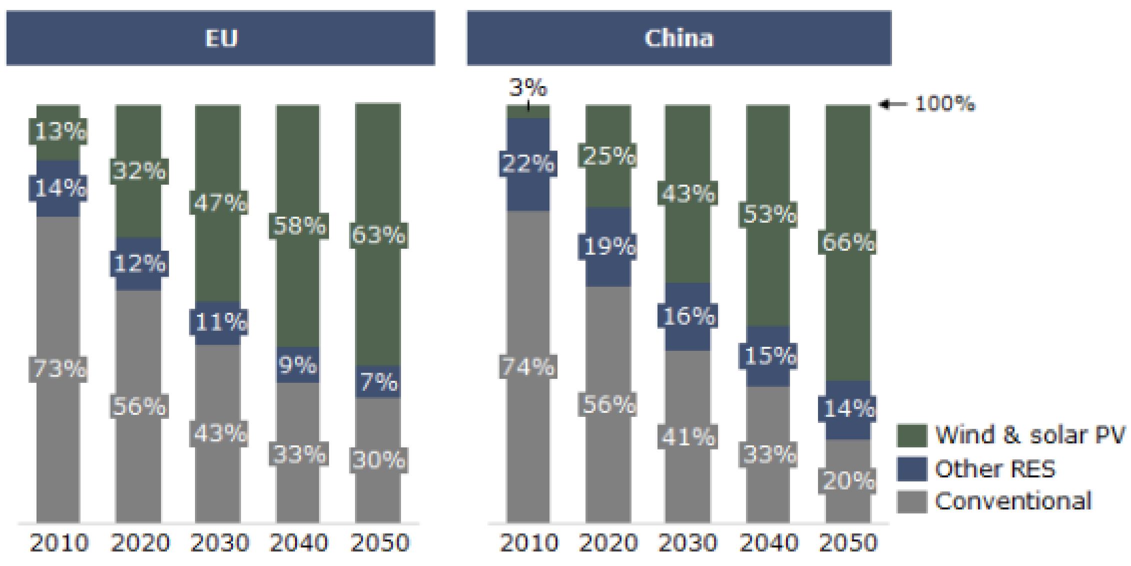
The European Union (EU) and Chinese electricity systems are undergoing historic structural changes as the deployment of renewables grows in both locations.

Both the EU and China are facing new challenges in managing and integrating intermittent generation output. As renewable energy penetration grows in both systems, these challenges will require changes to current market and operational paradigms.

In this paper we examine the outlook for renewables deployment in the EU and China as well as challenges and solutions for renewable energy integration. Based on our assessment of the situation in both locations, we propose a number of recommendations for Chinese energy policymakers relating to renewable energy integration.

In both the EU and China, AFRY analysis suggests that a combination of continued technology cost reduction, policy support and investment will lead to significant future capacity deployment of, in particular, wind and solar PV. This is shown in Figure 1 below.

Figure 1 Historical and projected shares for capacity by type in the EU and China (AFRY Central Scenario)

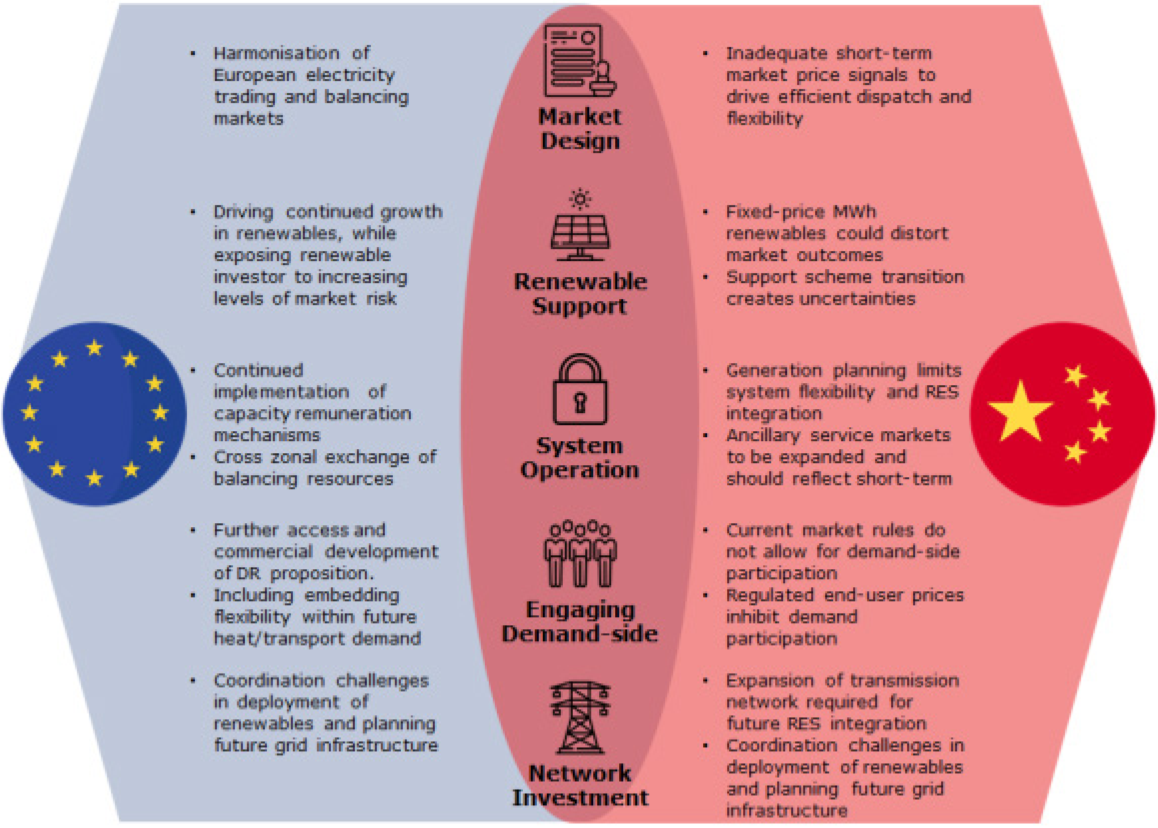


Note: RES: Renewable Energy Sources. 'Other RES' includes hydropower, biomass and other renewable sources; 'Conventional' includes coal, CCGT, nuclear and other conventional sources.

Source: EU: AFRY Analysis. China: National Bureau of Statistics (for historical data); AFRY analysis (for projections).

While the EU and Chinese electricity systems are very distinct, both locations will face a range of similar challenges in incentivising investment in, and integrating the output from, these capacities. We identify a range of common challenges in Figure 2 below.

Figure 2 Challenges integrating renewable generation technologies in China and the EU



Source: AFRY Management Consulting

We highlight four main areas of challenge for the European electricity system.

Supporting RES investment – while accelerating investment in RES is critical, as renewables become a larger share of overall generation and further technology cost efficiencies are realised, the potential inefficiencies of fixed feed-in tariff schemes – which distort wholesale price signals and risk excessive government support payments – are exacerbated. Finding new frameworks for supporting RES investment that minimise the cost to governments (and consumers) while exposing RES plant to market signals will be necessary.

Maintaining system stability and reliability – higher penetration of renewable generation technologies means system operators will face different challenges in maintaining the stability and reliability of the system. Renewable generation is less predictable, less controllable and non-synchronous, so system operators will need to review the requirements for reserve, response and other ancillary services and identify new sources to provide this flexibility.

Promoting consumer engagement and wider innovation – with the anticipated electrification of heat and transport, together with advances in ICT infrastructure, the scope for demand side response to provide a cost-effective source of flexibility will be increasingly important. Removing technical, commercial and regulatory barriers to innovative business models looking to exploit this potential will be pivotal. In a similar manner, barriers to deployment of new technology solutions such as battery energy storage systems will also need to be addressed if RES deployment is to be achieved at a reasonable cost.

Encouraging further market integration – cost-effective decarbonisation requires a coordinated approach to developing and accessing resources. The lowest cost renewable resources and flexibility providers may be in neighbouring markets. As the demand for renewables increases, effective integration of markets and associated investment in interconnection will offer lower cost solutions to delivering a low-carbon future.

As China implements its 2030 and 2050 targets (20% and 50%, respectively) for non-fossil fuels in the energy mix, renewables (in particular intermittent generation sources) will make up an increasing share of the generation mix. AFRY's own projections suggest that wind and solar photovoltaic (PV) capacity in China could exceed 2500GW by 2050. The electricity system in China faces many of the same challenges as the EU.

Achieving the targeted renewable energy penetration will require incentivising new investment in renewable technologies through incentive mechanisms, and market reforms enabling new revenue streams. In this decade, finding a viable alternative to the current Feed-in Tariff (FiT) mechanism will be crucial in achieving this. In addition, the current capacities under fixed-price FiTs may cause some price distortions as markets are liberalised.

As more intermittent renewable energy sources are brought into the system, new mechanisms will need to be put in place to provide the right short-term operational signals to enable greater flexibility in balancing the system. This challenge will include designing and deploying appropriate forward and spot electricity market arrangements, ancillary service markets and incentivising investment in flexibility provision, both from existing capacities and new technologies such as energy storage and demand participation.

In the long-term, the integration of renewable energy will require an active demand side in China. Consumers engaged through demand response and other forms of demand participation will be an important source of system flexibility, but currently (in most provinces) lack the opportunity and incentives to do so. The emerging spot market rules also lack demand-side integration, further limiting the deployment of this important resource.

Market reform benefits will be amplified when provincial and regional markets are effectively integrated. Currently, efficiencies in the dispatch of least-cost and low-carbon technologies to meet demand across the country are not being realised.

Underpinning this challenge is the need to accelerate the deployment of competitive markets and deploy greater physical interconnection capacities between markets, to allow for effective market integration.

In Europe, we are observing a range of actions to address the challenges identified.

Replacement of fixed FiT mechanisms – to reduce the cost escalation risks brought about by significant renewable energy investment, traditional FiT schemes are being replaced by competitive allocation (auction) mechanisms, lowering the cost of delivering the investment. There is also an increasing emphasis on the instruments themselves addressing investor risk through more market-based instruments, such as contracts for differences that incentivise the developer to participate in the traded markets.

Development of new products and markets – system stability concerns in a high RES market mean reserve and response services are much more variable and we are starting to see a trend away from long-term contracts towards shorter-term procurement, closer to real time. Alongside this short-term perspective, ongoing concerns over the economics of thermal generation have seen the introduction of capacity remuneration mechanisms to ensure long-term security of supply.

Addressing barriers to demand-side participation – a range of initiatives to encourage greater use of DSR and other new sources of flexibility are emerging. These include direct action such as requiring procurement of volumes of DSR as part of meeting balancing or capacity requirements, or amending rules on aggregation activities to enable new business models to emerge, or wider changes to market pricing to reflect more accurately the dynamically changing value of flexibility to the market that DSR can provide.

Harmonisation of balancing rules and promotion of interconnection – the EU has an established process to identify Projects of Common Interest - critical infrastructure that increases the interconnectivity and integration of the EU electricity system supports their development through sharing of the costs between the markets. More recently, they have promoted the cross-border exchange of balancing resources through a series of initiatives as part of the implementation of the Electricity Balancing Guidelines.

In this paper, taking into account the above solutions under consideration in the EU, and our assessment of the challenge of renewable energy integration faced by the future electricity system in China, we conclude with the following recommendations for policymakers:

- Future renewable energy investments will require mechanisms to handle generator volume and price risk, while at the same time realising cost reduction. These mechanisms should enable greater integration of renewables with China’s new electricity markets. Volume risk can be addressed with greater market integration of new renewables, alongside a hedging mechanism to address price risk. We recommend transitioning support schemes to contracts for difference, which have proven to be effective in providing investor certainty, while at the same time allowing exposure to markets. In addition, support levels under these contracts should be auctioned, so as to allow the market to bring forward cost reductions.

- We recommend the rapid implementation of competitive electricity market reforms: The future market should be technology neutral (including demand side technologies), should be integrated across provinces, and should enable trading as close to real-time as possible. Centralised auctions at regular intervals may not be the most effective means of achieving this. Allowing for trading across a wide range of timeframes, and close to real-time, will allow for the market to better capture the intermittency of greater wind and solar PV capacities – enabling the more efficient deployment of existing capacities, whether intermittent renewables or technologies required to balance a system with growing intermittency.

- Integrating renewables will require investment in flexibility. The optimal investments are most likely to be delivered by effective market signals, particularly short-term signals. China's provincial spot markets should be designed to allow the market to signal more accurately the varying costs of intermittency from greater wind and solar PV capacity shares. In parallel, the procurement of reserves should happen close to real-time, again to reflect the greater short-term uncertainty brought about by intermittency. Markets should be allowed to display volatility, as this will represent important revenue streams for flexibility providers, who will deliver essential services in order to integrate intermittent renewables.

- A participative demand side will provide a particularly important additional source of flexibility for renewable energy integration, as well as a counterbalance to potentially non-competitive generation-segment trading behaviour. Markets should evolve to allow active demand side participation.

- Markets should be integrated. Allowing efficient trading across regions will enable renewables to discover demand where it exists. To enable this, interconnection between provincial and regional markets should be strengthened where constraints arise. A parallel benefit of this will be to reduce the overall cost of developing and maintaining the electricity systems across integrated provinces and / or regions.

1. INTRODUCTION

1.1 Overview of report

By 2030, the EU is projecting a 65% increase in renewable generation capacity with around 300GW of new renewable power plants (much of it based on wind or solar energy) being commissioned, consistent with its climate change strategy and commitments under the 2015 Paris Agreement.

This represents an acceleration in the deployment of renewables compared to the previous decade and marks a fundamental change for electricity systems that have traditionally been based on thermal capacity.

Whereas the initial concern around renewables focused on addressing the market failures that made renewable generation uncompetitive with thermal power plants, the high and growing penetration of variable renewable resources, driven by strong cost reductions and policy support, is creating new challenges for system operators and policy makers. Most notably:

- maintaining system reliability given the stochastic and variable nature of the renewable resource; and

- ensuring efficient market signals for investment to deliver a secure, low-carbon generation mix at reasonable cost.

Within Europe, changing electricity market design to improve pricing signals and access a wider set of services from distributed energy resources is seen as part of the solution. As similar trends in renewable deployment are anticipated in the Chinese electricity markets, understanding how EU markets are adapting to these changes will provide a useful insight into the options for future-proofing the Chinese electricity market design.

In this report we aim to provide an overview of how the challenges of integrating high levels of renewable capacity are being approached in the European electricity system and draw out insights for future market design in China given the similar trends expected.

1.1.1 Structure of this report

The remainder of this report is structured as follows:

- Section 2 provides an overview of how the European and Chinese electricity markets may look in 2030, including an examination of the key drivers of change;

- Section 3 describes the main challenges that electricity markets will face in integrating very high levels of renewable generation and why this may be a barrier to achieving future energy and climate policy targets;

- Section 4 outlines some of the solutions that are being considered in Europe and assesses their applicability for consideration in China.

1.2 Conventions

- All monetary values quoted in this report are in Euros in real 2018 prices, unless otherwise stated.

- Annual data relates to calendar years running from 1 January to 31 December, unless otherwise identified.

- Plant efficiencies throughout this report are defined at the Higher Heating Value (HHV) basis. Fuel prices are similarly quoted on a gross (HHV) basis.

1.2.1 Sources

Unless otherwise attributed, the source for all tables, figures and charts is AFRY Management Consulting.

1.2.2 Abbreviations

Item	Description
AC	Alternating Current
ASHP	Air-Source Heat Pump
BEV	Battery Electric Vehicle
CO_2e	Carbon dioxide equivalent
CfD	Contract for Difference
CRM	Capacity Remuneration Mechanism
DR	Demand Response
DSR	Demand Side Response
EC	European Commission
ENTSO-E	European Network of Transmission System Operators for Electricity
ETS	Emission Trading Scheme
EU	European Union
EV	Electric Vehicle
FiT	Feed-in-Tariff
GB	Great Britain

Item	Description
GHG	Greenhouse Gas
GSHP	Ground-Source Heat Pump
GW	Gigawatt
GWh	Gigawatt hour
HEV	Hybrid Electric Vehicle
HHV	Higher Heating Value
HVDC	High Voltage Direct Current
Hz	Hertz
ICE	Internal Combustion Engine
kW	Kilowatt
kWh	Kilowatt hour
Mt CO_2e	Million tonnes of Carbon dioxide equivalent
Mtoe	Million tonnes of Oil Equivalent
MW	Megawatt
MWh	Megawatt hour
PHEV	Plug-in Hybrid Electric Vehicle
PPA	Power Purchase Agreement
RES	Renewable Energy Source
RoCoF	Rate of Change of Frequency
RPM	Revolutions Per Minute
SO	System Operator
TYNDP	Ten Year Network Development Plan
tCO_2/MWh	Tonnes of Carbon dioxide per Megawatt hour
TSO	Transmission System Operator
TW	Terawatt
TWh	Terawatt hour

2. FEATURES OF THE 2030 ELECTRICITY SYSTEM

In this section, we discuss how the EU and Chinese electricity systems may change by 2030. While there is always uncertainty over exactly how electricity systems and markets will evolve, we use existing projections to illustrate the key features of the European and Chinese electricity systems and markets in 2030, and the drivers (commercial, technical and policy/regulatory) behind these developments.

While we discuss the EU and China markets separately, several common themes emerge. These include evolving approaches towards renewable energy subsidies, the need for increased flexibility in system operation, and evolving market mechanisms driven by the changing nature of the electricity sector. Together, these suggest that insights from Europe may be valuable when deciding on the next steps in the reform of electricity market design in China. Their key projections are as follows:

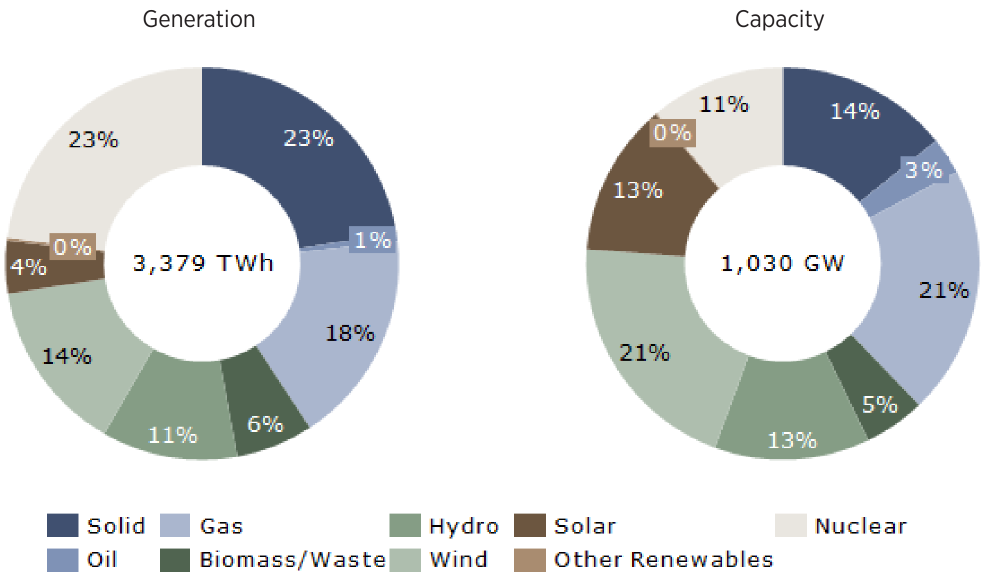
- renewables growth will accelerate over the next decade;
- concurrent growth in electricity demand will offer the potential for significant additional demand-side response;
- electricity systems will become increasingly decentralised and distributed energy resources will become more important; and
- interconnection between national/regional markets will become more important and cross-border flows and sharing of system services (e.g. balancing reserves) will increase.

2.1 European Union

2.1.1 Background

The current EU electricity generation mix is summarised in Figure 3. It comprises of just over 1TW of installed capacity, generating approximately 3,400TWh per annum. Around half of the capacity is renewable, with two-thirds of this being 'intermittent' (i.e. wind - onshore and offshore - and solar). This renewable capacity provides around a third of annual generation, with wind and solar accounting for around half of this volume.

Figure 3 Estimated EU electricity generation and capacity in 2020



Source: European Commission, EUCO3232.5 Scenario

The current situation is unlikely to persist as the European electricity system undergoes major changes. The continued transformation of the electricity mix will be largely driven by the need to deliver EU energy and climate targets.

2.1.2 EU energy and climate targets

EU energy and climate targets are currently undergoing reform. To account for this shifting regulatory landscape, we initially examine the existing targets before exploring the increasing climate ambition and legislative reform expected in the near future.

2.1.2.1 Existing EU decarbonisation targets

The 2030 climate and energy framework includes EU-wide targets and policy objectives for the period from 2021 to 2030. The framework[1] was adopted by the European Council in October 2014 and included targets in a number of areas including greenhouse gas (GHG) emissions, renewable energy share, energy efficiency improvements and interconnection capacity. The targets for renewables and energy efficiency were revised upwards in the run-up to the adoption of the Clean Energy Package in June 2019.

The targets and policy objectives, outlined in Figure 4, include:

1 European Commission, A policy framework for climate and energy in the period from 2020 to 2030 https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52014DC0015

- **GHG emission target** refers to a reduction in net GHG emissions of at least 40% in 2030, and 80-95% in 2050, relative to 1990 levels.

- **Renewable energy target** of at least 32% refers to the share of renewable energy in gross final energy consumption.

- **Energy efficiency target** is a target for both total primary energy and final energy consumption in 2030. This is calculated as achieving 32.5% efficiency in 2030 relative to the 2007 baseline scenario.

- **Interconnection policy objective**[2] refers to the European Council calling on the EC to report regularly on how to achieve 15% interconnectivity by 2030. The 15% interconnectivity target is defined as the ratio between the interconnection capacity and the installed generating capacity.

Beyond this timeframe, the EC have also published the Energy Roadmap 2050[3] and A Clean Planet for all[4], which reaffirms the Commission's commitment to reduce GHG emissions by 80-95% by 2050 relative to 1990 levels.

Figure 4 EU framework for climate and energy

	GHG emissions	Renewable energy	Energy efficiency	Inter-connection
2050	80%			
2030	40%	32%	32.5%	15%
2020	20%	20%	20%	10%

Source: European Commission, 2030 Climate & Energy Framework

2 European Commission, Outcome of the October 2014 European Council https://ec.europa.eu/clima/sites/clima/files/strategies/2030/docs/2030_euco_conclusions_en.pdf

3 European Commission, Energy Roadmap 2050 https://ec.europa.eu/energy/sites/ener/files/documents/2012_energy_roadmap_2050_en_0.pdf

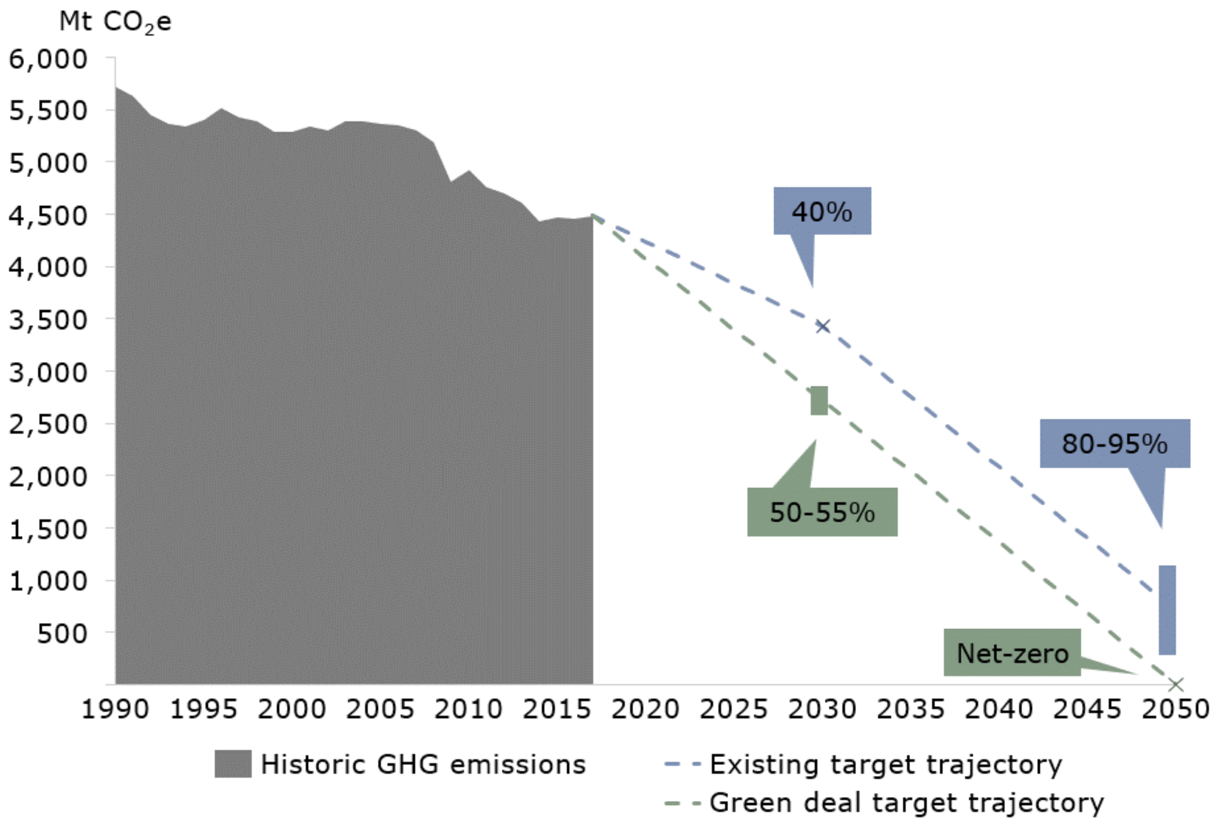
4 European Commission, A Clean Planet for all https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52018DC0773

2.1.2.2 The EU's increasing climate ambition

During 2019, political momentum gathered to strengthen existing energy and climate targets, as set out in the Commission's 'European Green Deal'. This aims to reset the EU's commitment to tackling climate change by strengthening decarbonisation targets in line with its commitment to global climate action under the Paris Agreement signed in 2015. Although it has several elements, the overarching objective of the European Green Deal is to achieve climate neutrality by 2050, an ambition the EC intend to enshrine into 'Climate Law'.

Not only would this strengthen Europe's commitment in the longer-term, it is also expected to be complemented by a plan to increase the 2030 greenhouse gas reduction target to at least 50% (and towards 55%) compared to 1990 levels, as demonstrated in Figure 5.

Figure 5 Historical and target GHG emissions



Source: European Commission, The European Green Deal

2.1.3 Evolution of the EU electricity system

What these targets mean for the future generation mix is uncertain, and there are numerous projections as to how the energy system (and the electricity sector) may evolve. To illustrate this, we use our own AFRY modelling and a set of European

Commission scenarios called the EUCO scenarios. These EUCO scenarios formed the basis for a number of impact assessments and for the negotiations of the legislative acts proposed under the EU 2030 energy and climate policies.

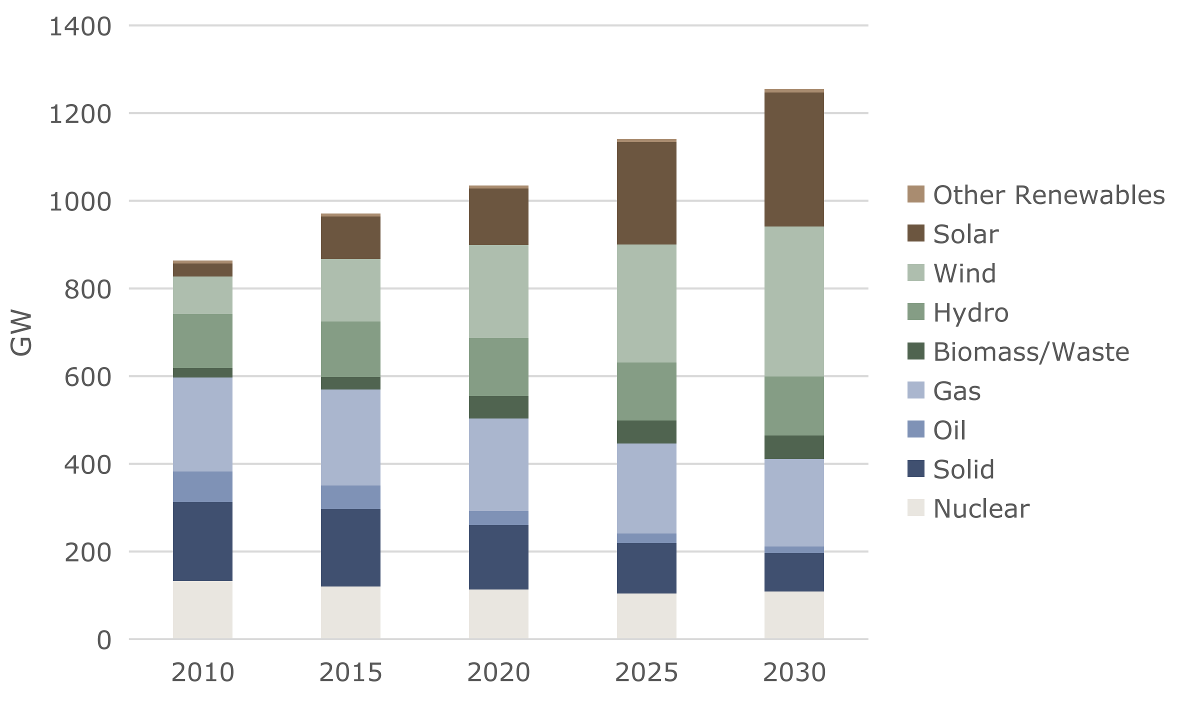
The most recent modelled scenario is called the EUCO3232.5[5]. The EUCO3232.5 scenario models the impact of achieving the renewable energy target of 32% and the energy efficiency target of 32.5% (resulting in a reduction of GHG emissions of 45.6% relative to 1990), in alignment with the Clean Energy package.

This scenario highlights several emerging trends and key features of the possible future EU electricity system.

2.1.3.1 Renewable generation capacity will grow rapidly

Figure 6 shows how total generation capacity is likely to develop. In particular, the capacity of renewable generation has doubled over the last decade. This rapid growth is expected to continue with an additional 308 GW of renewable capacity connecting to the EU electricity system over the next 10 years from 474 GW in 2020 to 782 GW in 2030. Wind and solar are the big movers, with capacity forecast to increase by 131 GW and 175 GW respectively, while hydro and other renewables remain relatively stable.

Figure 6 EU electricity capacity from 2010 to 2030

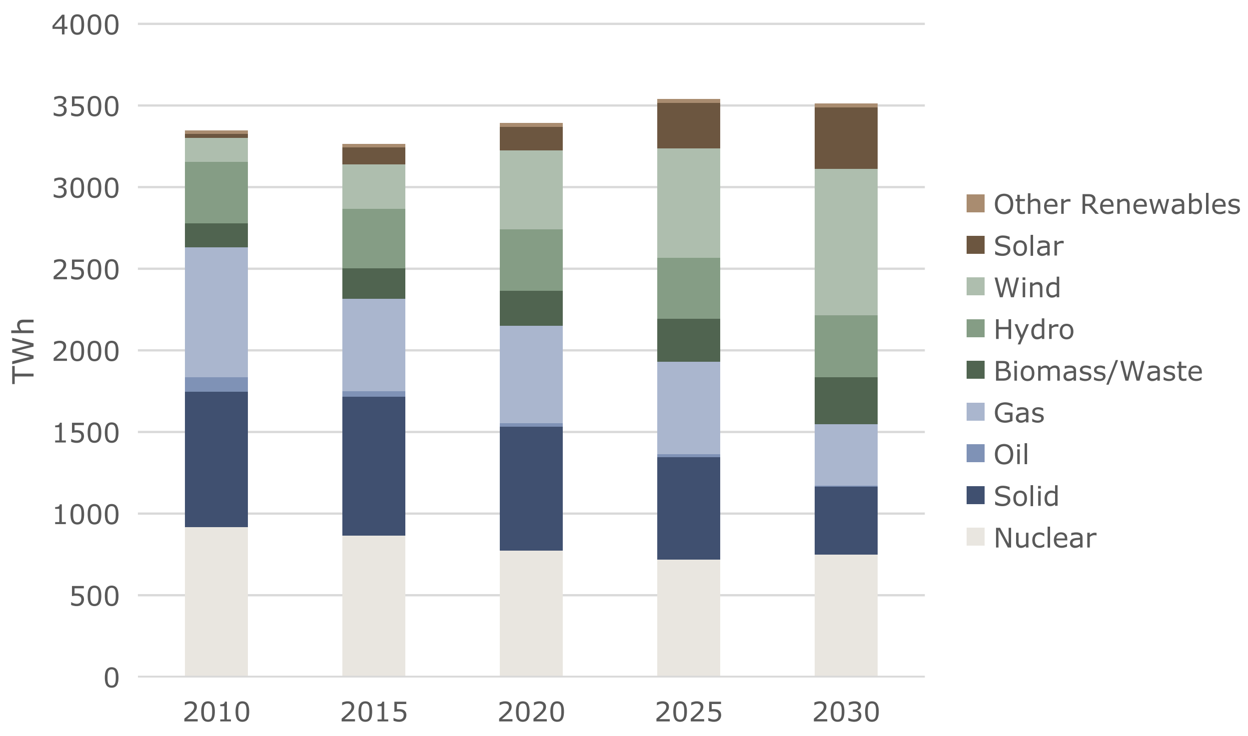


Source: European Commission, EUCO3232.5 scenario

5 European Commission, Technical Note: Results of the EUCO3232.5 scenario on Member States https://ec.europa.eu/energy/sites/ener/files/technical_note_on_the_euco3232_final_14062019.pdf

The increased renewable capacity will result in renewables accounting for almost half of all EU generation by 2030, with fossil fuel-fired generation representing less than a quarter.

Figure 7 EU electricity generation from 2010 to 2030



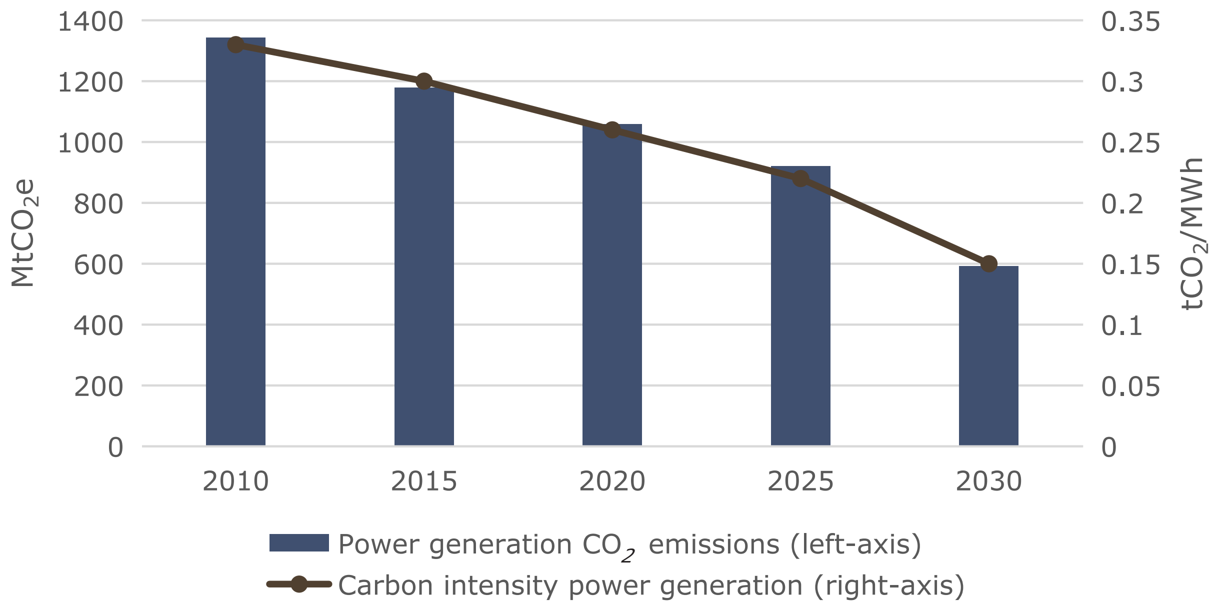
Source: European Commission, EUCO3232.5 scenario

2.1.3.2 Fossil fuel capacity and generation will continue to fall

The last decade has seen fossil fuel-fired (electricity sourced from solids, oil, and gas) generation and capacity decline by 20% and 16% respectively. This downward trend is forecast to continue with generation falling by 42% and capacity falling by 22% from 2020 to 2030. The rate of capacity decline is slowed by the need for dispatchable power plants to safeguard security of supply.

The falling fraction of fossil fuel-fired generation will reduce the average carbon intensity of EU electricity production. This is expected to drop from 0.26 tCO_2/MWh in 2020 to 0.15 tCO_2/MWh in 2030 (see Figure 8).

Figure 8 Power generation CO_2 emissions and carbon intensity



Note: Power generation includes district heating and carbon intensity includes steam production.
Source: EUCO3232.5 scenario, European Commission

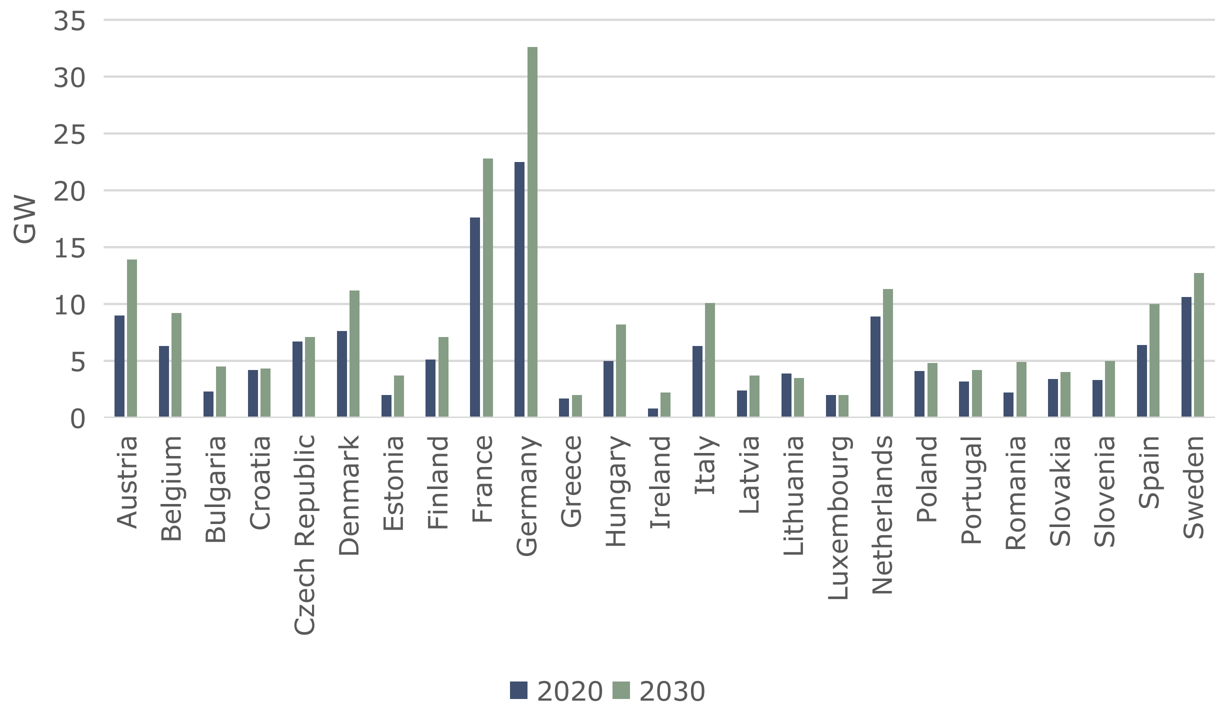
2.1.3.3 Interconnection will grow

EU electricity markets are forecast to becoming increasingly interconnected over the next decade. This is in line with the European Council target for Member States to achieve an interconnection level of 10% by 2020 and the policy objective of 15% by 2030.

The evolution of interconnection sits within a wider context of European grid development. The 10-year network development plan (TYNDP) that the European Network of Transmission System Operators for Electricity (ENTSO-E) publishes every two years presents how to develop the power grid in the next 10 to 20 years. This long-term plan for how the electricity transmission grid should evolve is based on extensive data collection and analysis, and is flexible enough to accommodate shifting policy landscapes, macroeconomic trends, and technological evolutions.

The capacity of interconnections is forecast to increase from around 150 GW in 2020 to just over 200 GW in 2030, allowing for increased optimisation of capacity and generation across the EU electricity system (see Figure 9).

Figure 9 EU Member State export interconnection capacity from 2020 to 2030



Source: AFRY Management Consulting

Increased interconnection capacity will be crucial to accommodate increasing levels of intermittent renewables and efficiently share capacity and generation across the European electricity system.

New interconnection investment will largely be driven by TSO support and/or market price differentials stemming from:

- generation mix differences between neighbouring electricity markets;
- distinct load profiles in different power markets;
- existing levels of interconnection capacity in place; and
- spatial and temporal correlation of weather patterns across electricity markets.

2.1.3.4 Increased flexibility and energy storage

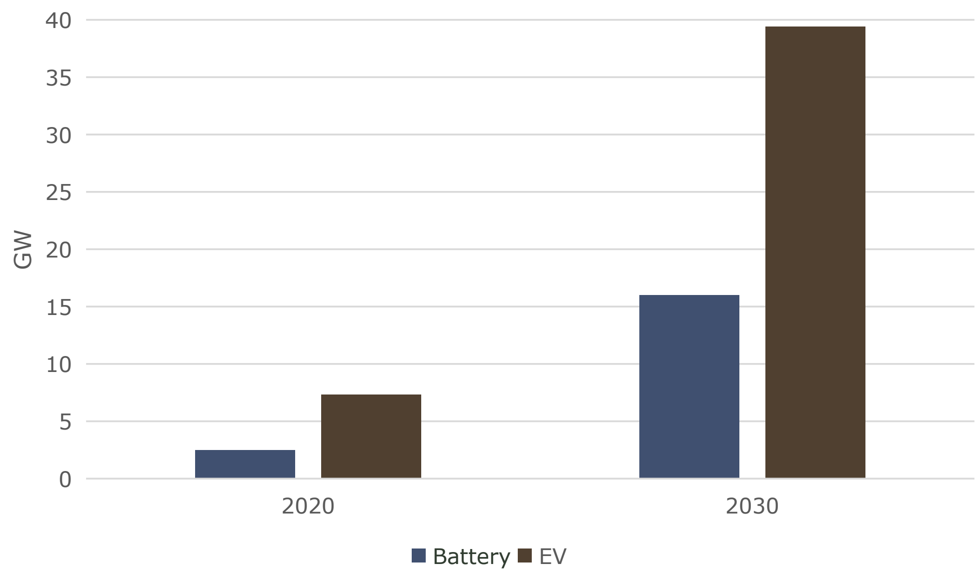
Rising levels of intermittent and asynchronous wind and solar capacity will drive an increasing requirement for flexible technologies to balance the EU electricity system (see Figure 10).

Figure 10 Illustrative drivers of flexibility

Source: AFRY Management Consulting

Energy storage is a set of technology types that offer different speeds of flexibility over different timeframes. For example, lithium-ion batteries, either stationary grid-connected or in electric vehicles (EVs), offer the technical ability to rapidly charge or inject power to the electricity system, allowing them to balance sub-second frequency fluctuations or arrest steep frequency deviations caused by power plant outages. In addition to this, longer duration batteries offer the promise of arbitraging out daily grid supply-demand imbalances, charging during periods of surplus generation and injecting power when the grid is under supplied.

Figure 11 EU battery and EV capacity from 2020 to 2030

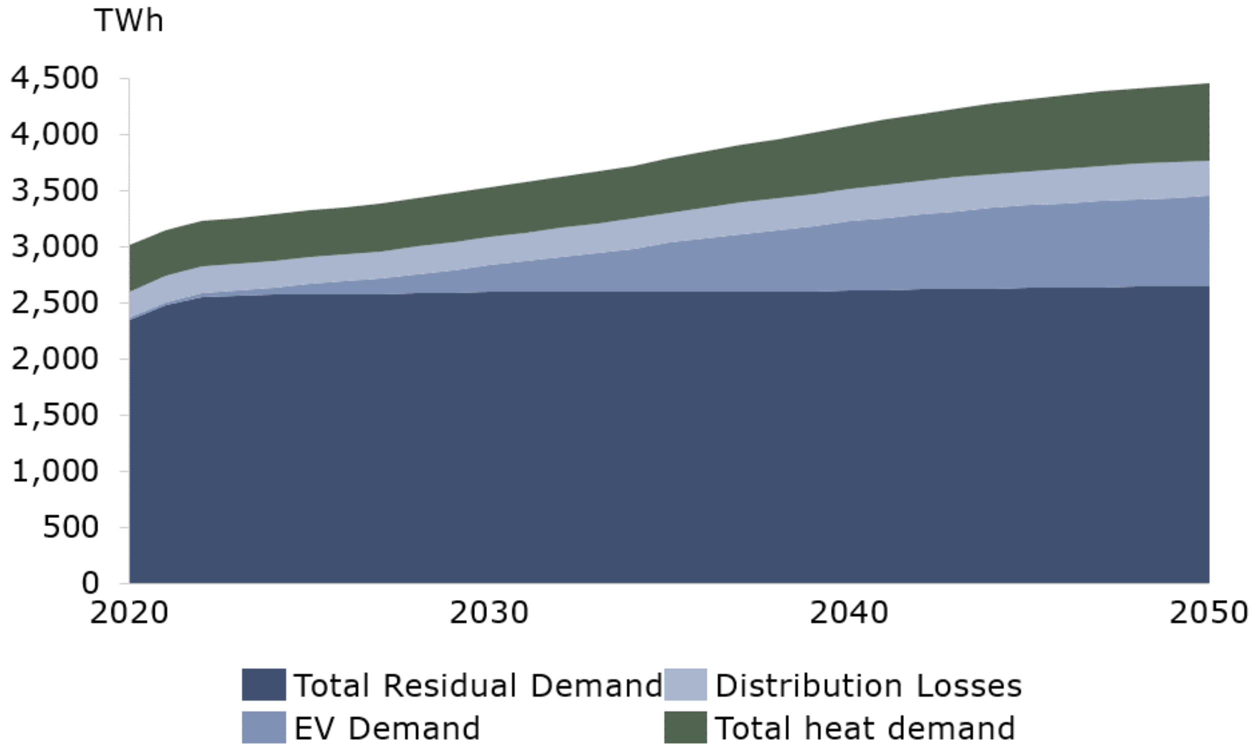


Source: AFRY Management Consulting

2.1.3.5 Electrification of the heat and transport sectors will boost demand

Electricity is a vector for decarbonising certain processes. For this reason, Europe is forecast to experience concurrent growth in electricity demand in the period to 2050, mainly driven by electrification of transport and heat (see Figure 12). While the changes may be less pronounced before2030, they will thereafter become more prevalent, with electricity expected to be the largest energy vector in both heat and transport by 2050.

Figure 12 EU power demand by sectors from 2020 to 2050

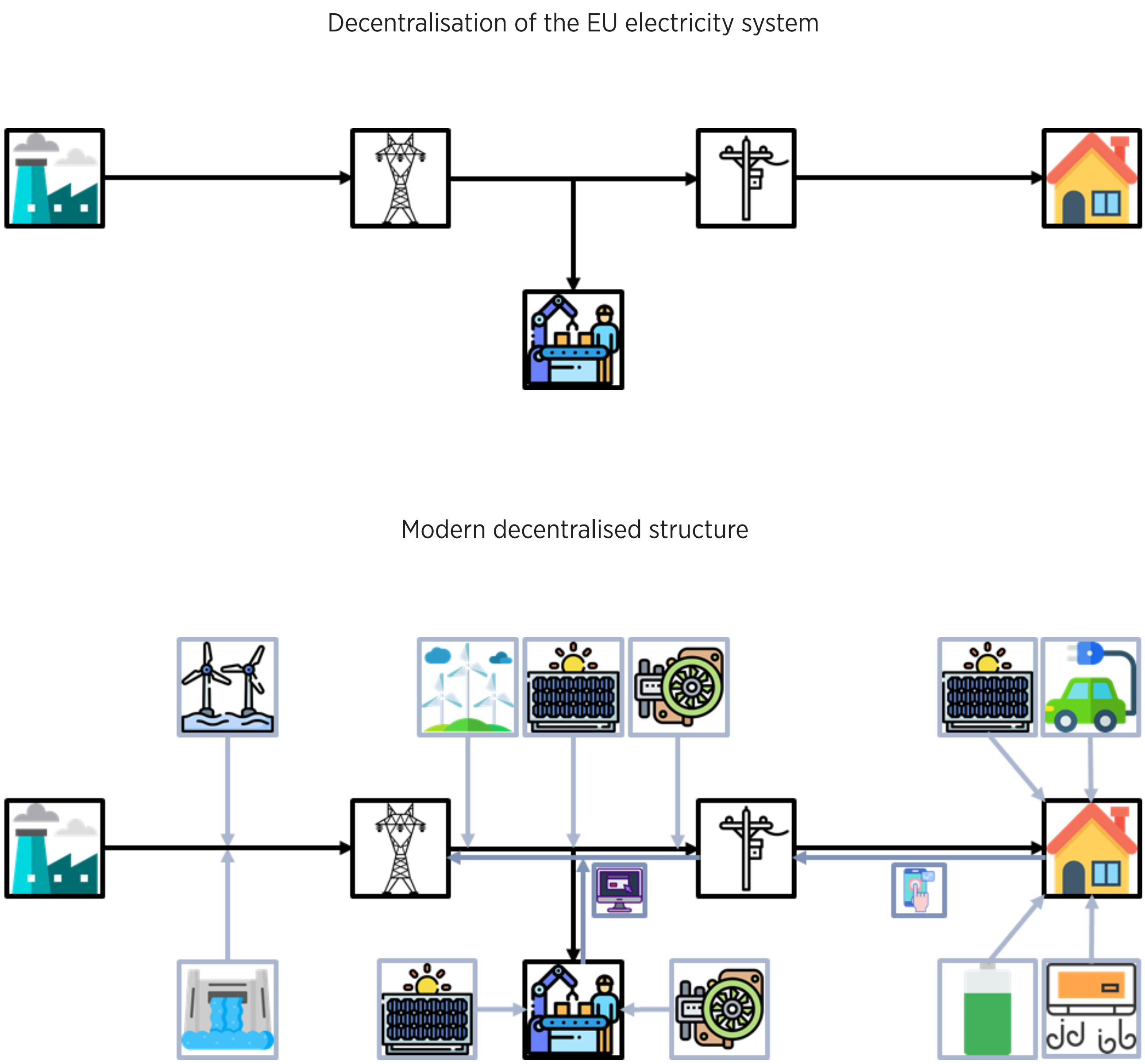


Source: AFRY Management Consulting

2.1.3.6 Decentralisation of the electricity system

Decentralisation of the European electricity system is an umbrella term referring to an increasingly demand-responsive, bi-directional, and equally-distributed power system (see Figure 13). Advancing technology and the necessity to decarbonise have revolutionised the traditional, centralised grid arrangement. This has resulted in the connection of increased distributed generation and energy storage at every level of the power network, and increasing levels of responsive demand.

Figure 13 Decentralisation of the EU electricity system



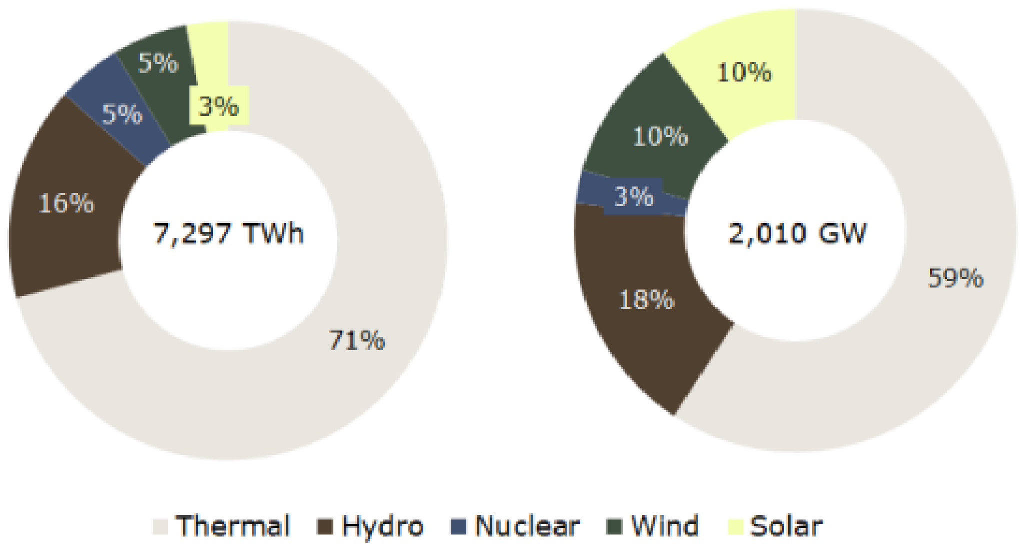
Source: AFRY Management Consulting

Demand response (DR) refers to price-sensitive load that can increase, reduce, and/or shift power demand in response to market needs. According to AFRY's internal analysis, the capacity of DR in the EU27 is expected to more than double over the next decade, increasing from 7GW to 15GW. This is a useful proxy for showing how the EU electricity system is becoming increasingly smart and decentralised.

2.2 China

2.2.1 Background

Figure 14 Overview of the Chinese electricity system in 2019



Source: National Energy Administration

At the end of 2019, China's electricity system remained dominated by thermal generation (at almost three quarters by volume dispatched) as shown in Figure 14. More than a quarter of generation is delivered by low-carbon generators including onshore wind, offshore wind, solar PV and nuclear power.

The country's generation capacity stood at just over 2000 GW, with more than half of this composed of thermal coal (1049 GW), followed by hydropower and intermittent renewables which make up almost 40% of total installed capacity.

The structure of China's generation capacity is largely driven by abundant coal and lignite reserves, mainly located in the northern regions of the country. Relatively little natural gas generation exists in the system (88 GW) due to restricted gas supplies, and therefore gas prices are high relative to coal.

2.2.2 Existing China energy transition targets

Driven by domestic air pollution concerns and global decarbonisation commitments, China is implementing a wide range of decarbonisation policies. These have been given further impetus under President Xi Jinping's "Energy Revolution", which includes "four revolutions and one cooperation".

Reforms are to be implemented across four energy sector segments including demand, supply, technologies and markets, as well as bolstering international collaboration and China's role in global energy governance institutions.

In particular, the supply-side "revolution" (or reform) calls for clean and low-carbon technologies to be promoted above conventional energy sources.

These guidelines, and others, have been translated into a number of key decarbonisation targets for 2020, 2030 and beyond.

- The 13th Five Year Plan includes a 2020 carbon intensity reduction target of 40-45% in comparison to 2005 levels, as well as a specific 2020 capacity deployment target for renewable energy (211 GW of new wind, solar PV and hydropower). The plan also aims to achieve delivery of 15% of primary energy consumption from non-fossil fuel sources and 9% of electricity from non-hydropower renewable energy;

- The Strategy for Energy Production and Consumption Revolution (2016-2030) aims to cap total energy consumption at within 6 billion tons of standard coal by 2030. Further aims are for non-fossil energy resources to supply 20% of total energy consumption, and for non-fossil power generation to account for 50% of total power generation (relative to 31% in 2019). Finally it calls for incremental energy demand to be met by non-fossil fuel sources, as well as the development of a 'modern energy system', which is often interpreted to mean market-driven energy supply and consumption;

- Under its Nationally Determined Contribution to the Paris Agreement in 2016, China committed to a series of binding decarbonisation targets. Central to this is an economy-wide carbon intensity target of -60% to -65% by 2030 relative to 2005 levels (this appears to be on track as of writing), with a peak in emissions around 2030;

- Further targets for the 2021 to 2025 period are under consideration as part of China's 14th Five Year Plan planning process. In addition, longer-term plans extending to 2035 are expected to be announced in the coming year. These are likely to include actions to strengthen reforms to the electricity system and accelerate the deployment of clean and low-carbon energy sources.

In Figure 15 below, we summarise these targets in 2020 and 2030.

Figure 15 Summary of key energy transition targets

	CO2 intensity	Non-fossil fuels in Primary Energy Consumption	Non-fossil fuel electricity generation
2050	-	>50%	-
2030	-60 to -65%	20%	50%
2020	-40 to -45%	15%	31%

Source: State Council, National Development and Reform Commission, National Energy Administration

Beyond these specific targets, a series of policies aim to promote the deployment of low-carbon technologies.

- A renewable energy Feed-in-Tariff affords all qualified renewable generators a fixed subsidy for each kWh of generation. The FiT has incentivised over 400 GW of new renewable capacity since it was first implemented in 2006, but is being closed to new capacities by 2021;

- A Renewable Portfolio Standard has been implemented to incentivise the consumption of renewable output. This is expected to be supplemented by a Green Electricity Certificate (GEC) to be launched in 2021;

- A range of tax incentives has been implemented for renewable energy generators, and charge exemptions for consumers who install distributed resources;

- A ban on new coal capacity deployment is in effect in a number of key load-centre regions;

- Provincial authorities have implemented a range of renewable energy targets and have offered some local subsidies for various renewable energy technologies;

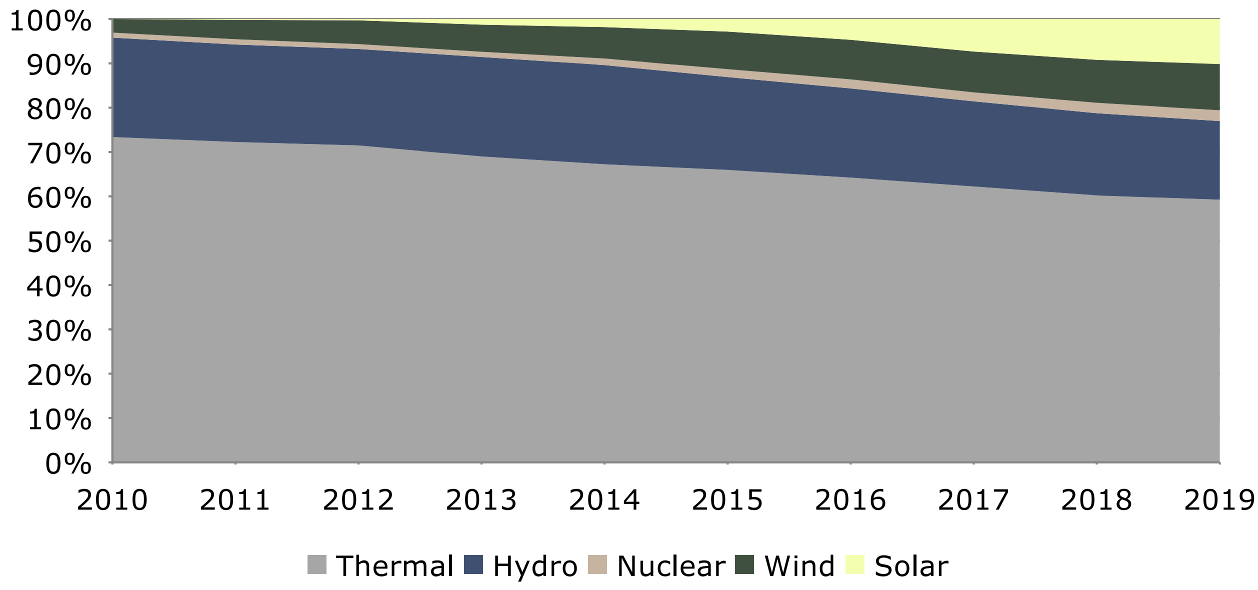
- Operational rules requiring minimum full-load hours for wind and solar PV in provinces with severe curtailment offer these technologies priority dispatch, ahead of conventional technologies.

These targets and policies are delivering a changing landscape in China's electricity sector, with low-carbon generation beginning to erode coal's predominant position.

2.2.3 Evolution of the Chinese electricity system

Over the past decade, China's renewable energy capacities (across hydro, wind and solar PV) have grown by 525 GW.

Figure 16 Composition of capacity by technology (2010-2019)



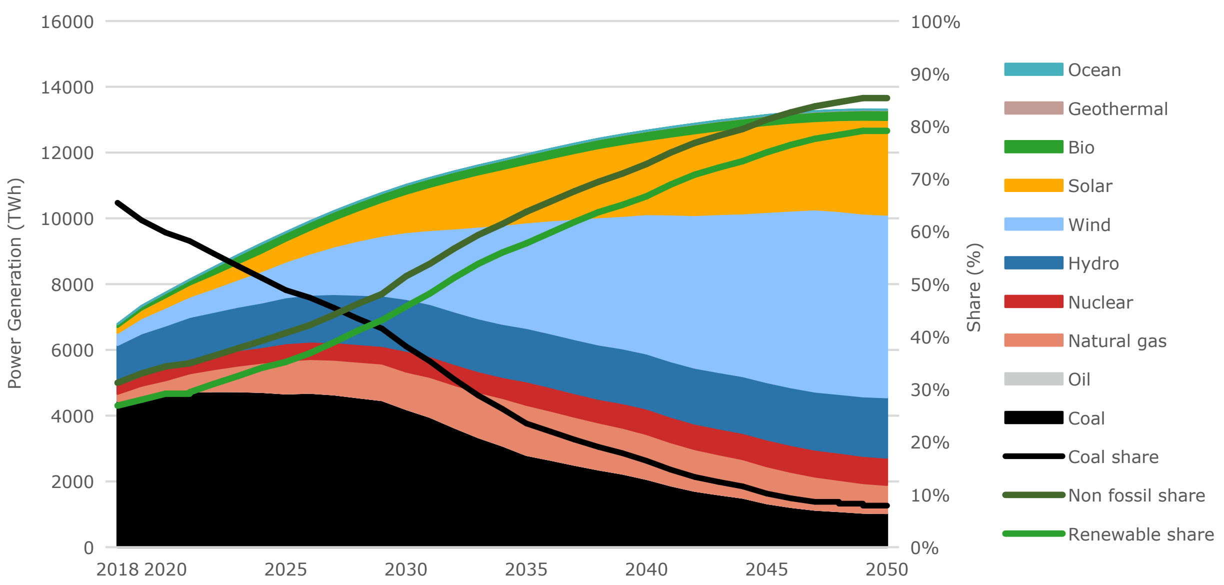
Source: National Energy Administration, China Electricity Council, AFRY Analysis

In 2019, renewables made up 39.5% of total capacity and 27.9% of total electricity generation. Total renewable energy curtailment dropped to about 51 TWh from 100 TWh in 2018. Curtailment of wind and solar dropped to 16.9 TWh and 4.6 TWh respectively, with the curtailment rate falling to 4% and 2% respectively. Renewables account for over 13% of primary energy consumption, with coal's share dropping below 58%.

Renewable energies in China are widely expected to play an increasingly important role in the energy mix. The falling costs of these technologies and a maturing supply chain are expected to be among significant drivers that could spur major deployment in the coming decades.

Looking ahead to 2030, research from the Energy Research Institute of the National Development and Reform Commission suggests that strong action to accelerate the energy transition could lead to renewable energy making up just over 45% of total generation in 2030. This is shown in Figure 17.

Figure 17 Projected generation by technology (2018-2050)



Source: Energy Research Institute of the NDRC - China Renewable Energy Outlook 2019

The system in 2030 is likely to be characterised by a range of changes compared to today's system, across both physical and policy features.

- Some regions could present with very high penetration of renewables. In Qinghai, Inner Mongolia, Hebei and other provinces, the proportion of intermittent renewables in generation volumes is likely to exceed 50%, with other key provinces such as Anhui, Henan, Hubei and Hunan not far behind;

- Renewables are likely to be cheap. In the last three years alone almost 30GW of 'grid parity' wind and solar projects have been brought forward. In AFRY's own projections for cost reductions we predict that costs for wind and solar will fall approximately 30-40% by 2050 relative to 2019. By 2030, onshore wind and solar PV are likely to be the most cost competitive generation technologies in the market;

- Markets are likely to play a much greater role in delivering electricity prices. Already in 2019, approximately 30% of all volumes in the market were traded and eight provincial spot markets are expected to launch soon with additional ones under consideration. The deployment of competitive short-term electricity markets will pose both opportunities and new challenges for intermittent renewable energies reaching such high proportions;

- The system will be more interconnected. As is the case in Europe, China is likely to deploy significant interconnector capacities in order to enable the consumption of plentiful renewables in the northern and south-western regions. Under the 13th Five Year Plan, electricity sector planners aimed to almost double West-to-East interconnection capacity from 140 GW in 2015 to 270 GW in 2020. Projections from local grid companies suggest the need for hundreds of GW of new interconnector capacities over the coming one to two decades;

- The system could experience regionally high levels of decentralisation. Significant capacities of distributed wind and solar PV are likely to have been deployed by 2030. Parallel deployment of customer-side batteries and demand response, enabled by virtual power plant contracts and distribution-level markets could mean that distributed renewables become the main form of renewable energy consumption in major, highly urbanised, load centres in the East China Grid region;

- Digitalisation is likely to be increasingly common. This will be driven by China's "Internet Plus" strategy throughout the 2020s, and is likely to yield a series of integrations of communication and energy technologies, enabling new features to emerge in system operation;

- Electrification of transport and industry is likely to progress. In 2030 this will likely be the primary driver of demand for electricity and will enable the replacement of coal as an end-use fuel under the ongoing "coal to power" conversion programme;

- Flexible resources are likely to be deployed more widely. This will be essential to integrate high levels of intermittent renewables. Thermal coal plants are being retrofitted to reduce ramp and start-up times. Grid-connected batteries and new pumped storage will also provide system balancing. Demand side resources are likely also to be tapped. At the same time, electric vehicles, heat pumps and hydrogen will bring important new flexible resources.

These changes across the system will enable system integration of renewable energy as planners seek to achieve targets set out in decarbonisation plans.

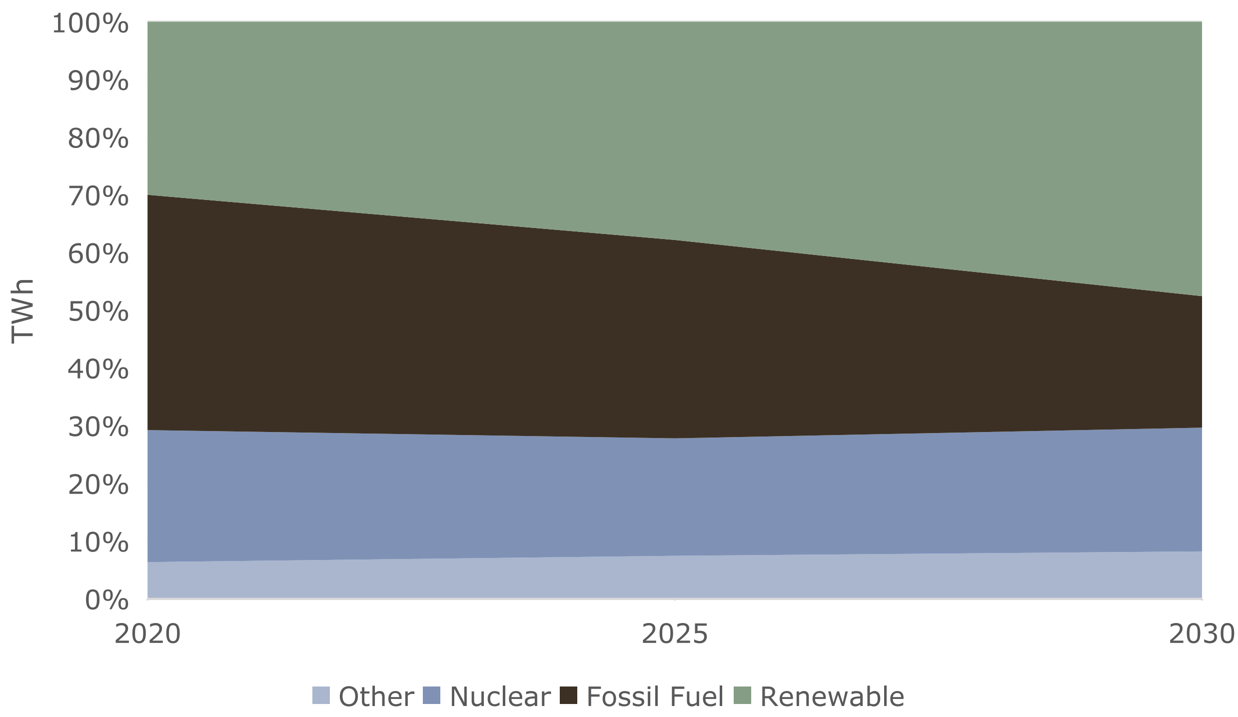
3. CHALLENGES TO DECARBONISING THE 2030 ELECTRICITY SYSTEM

In this section we will explore the key challenges facing the European and Chinese electricity systems as they respond to the need to integrate larger volumes of renewable capacity whilst ensuring a safe, secure and sustainable solution for energy consumers.

3.1 European Union

As examined in the previous section, renewables have experienced rapid growth in the EU over the last decade in compliance with binding GHG and renewable targets. This trend will continue, with renewables forecast to take fossil fuel-fired generation's crown as the leading fraction of EU generation by 2025 and account for half of total generation by 2030 (see Figure 18).

Figure 18 Fraction of EU generation by technology group



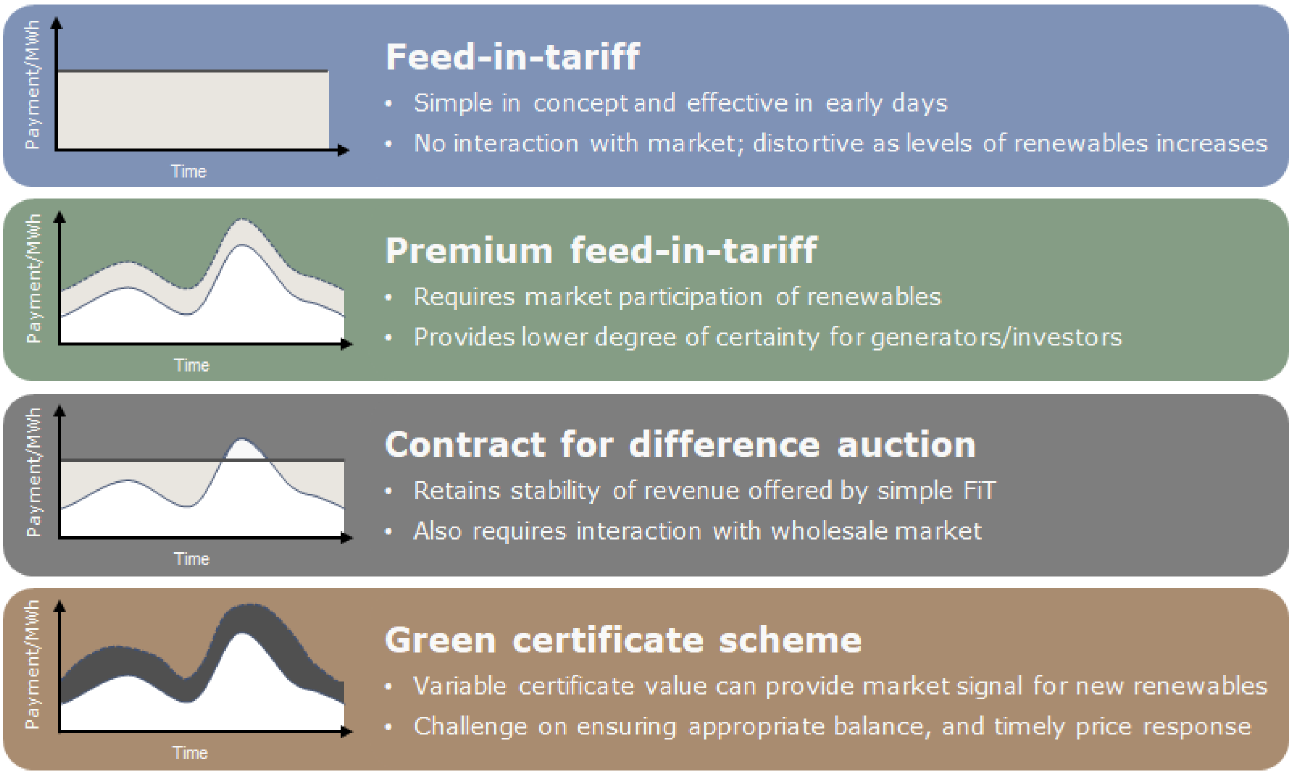
Source: European Commission, EUCO3232.5 scenario

Integrating increasing levels of renewable is a challenging task. As the electricity system operation becomes increasingly stressed, existing market design structures become less efficient and investment signals need to be redesigned; these issues will be examined in the following sections.

3.1.1 Renewable Incentives

The historical cost of renewables required European governments to introduce a wide range of financial support mechanisms to encourage the present renewable power plant deployment (see Figure 19).

Figure 19 Range of support mechanisms adopted across EU

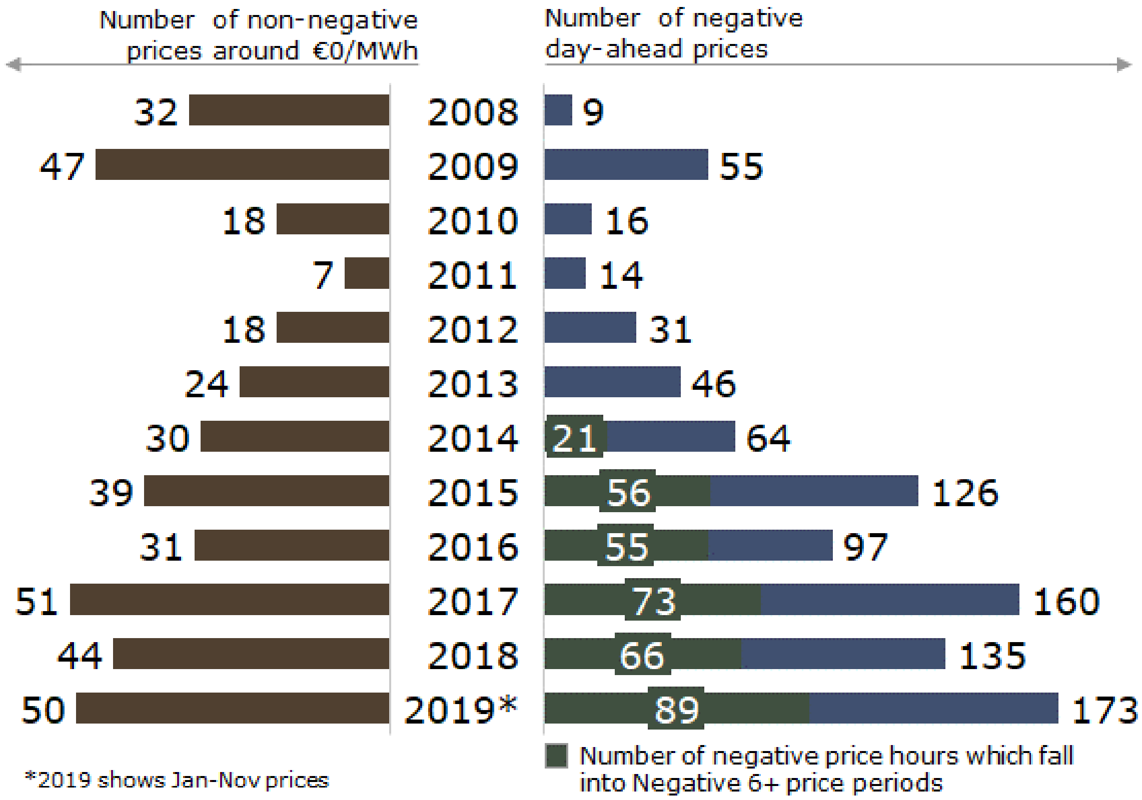


Source: AFRY Management Consulting

Fixed feed-in-tariffs (FiT) were initially popular and employed in European countries including the Czech Republic, France, Germany, Italy, and Spain. However, the lack of auction-based interaction with the market resulted in inefficient rate setting which often failed to take into account the rapid decline in renewable capital costs. In addition to this, early FiT structures without suitable limitations on the rate of deployment led to uncontrolled capacity build and the overspend of renewable subsidy budget allocations.

Early renewable subsidy structures in Europe were not dependent on wholesale power prices. This has resulted in distorting impacts such as negative prices (see Figure 20).

Figure 20 Evolution of zero and negative prices in Germany



Note: "Prices around €0/MWh" refers to prices between €0.01 - €0.99/MWh
Source: Netztransparenz.de

Unlike the early subsidy structure, merchant renewable projects (non-subsidised) and renewable projects under subsidy schemes which are exposed to wholesale power prices are subject to a number of barriers including:

- **Carbon price uncertainty:** Imposing a carbon price on fossil-fuel generators is unlikely to provide sufficient investment signals to investors in renewable capacity. The EU emission trading scheme (ETS) has experienced significant price volatility to date and the long-term pricing is highly uncertain due to the transient nature of the governments involved in shaping its fundamentals;

- **Cannibalisation of renewable prices:** This describes the depressive influence on the wholesale electricity price at times of high output from intermittent, weather-driven renewable generation. This will become increasingly important as renewable penetration increases;

- **Price and volume risk premiums:** Accurately modelling wholesale power price volatility, especially scarcity rent, is proving to be particularly complex. As a result, power purchase agreements (PPAs) may increase risk premiums due the uncertainty associated with accurately forecasting long-term renewable wholesale power revenue streams.

3.1.1.1 Renewable Incentive case studies

The Netherlands

The current support mechanism for renewable technologies in the Netherlands is the Stimulering Duurzame Energieproductie +, more commonly referred to as the SDE+. The scheme provides for a fixed unit income, structured as a one-way contract-for-difference (CfD) around an index of market prices.

The SDE+ has been in existence in its current form since 2011, and allows generators to carry over a limited volume of surplus subsidy-eligible generation for use in future years after 2015 (this is known as "banking"). From 2020, it is planned that the SDE+ will be superseded by the SDE++, which will assess and support projects on the basis of emissions avoidance (avoided tonnes of CO_2 emissions for each application using a particular benchmark). This measure is intended to widen the pool of technologies eligible to apply, including Carbon Capture and Storage (CCS).

Portugal

The Portuguese Government held a solar auction in July 2019, allowing applicants to bid for the allocation of public electrical grid capacity at specific sites, spread across 24 slots which ranged in size from 10 to 200 MW. A total volume of 1.4 GW was auctioned.

Applicants had the opportunity to tender under an option of two remuneration modalities, guaranteed and general. The guaranteed remuneration modality functioned as a FiT, guaranteeing a fixed price for the solar electricity generated, whilst the general remuneration modality generators were exposed to market price or private contracts.

The July 2019 auction achieved highly competitive clearing prices, with most consultants and market participants estimating Internal Rates of Return (IRRs) of under 5% for the projects.

3.1.2 Challenges of RES integration to system operation

According to forecasts, the growth in EU renewable capacity in the run up to 2030 is set to be dominated by solar and wind capacity. These technologies share a number of characteristics:

- **Non-synchronous:** Photovoltaic generators and wind converters are decoupled from the synchronous grid frequency.

- **Intermittent/variable:** Solar and wind technologies are affected by multiple meteorological parameters, particularly wind speed and wind direction for wind energy, and cloud cover and solar irradiance for solar energy. The daily, monthly and seasonal generation profiles for these technologies vary dramatically.

- **Non-dispatchable:** This refers to the capability of an energy source to change its output on demand. Unconstrained wind and solar capacity have no ability to increase power output on demand and limited ability to decrease power output.

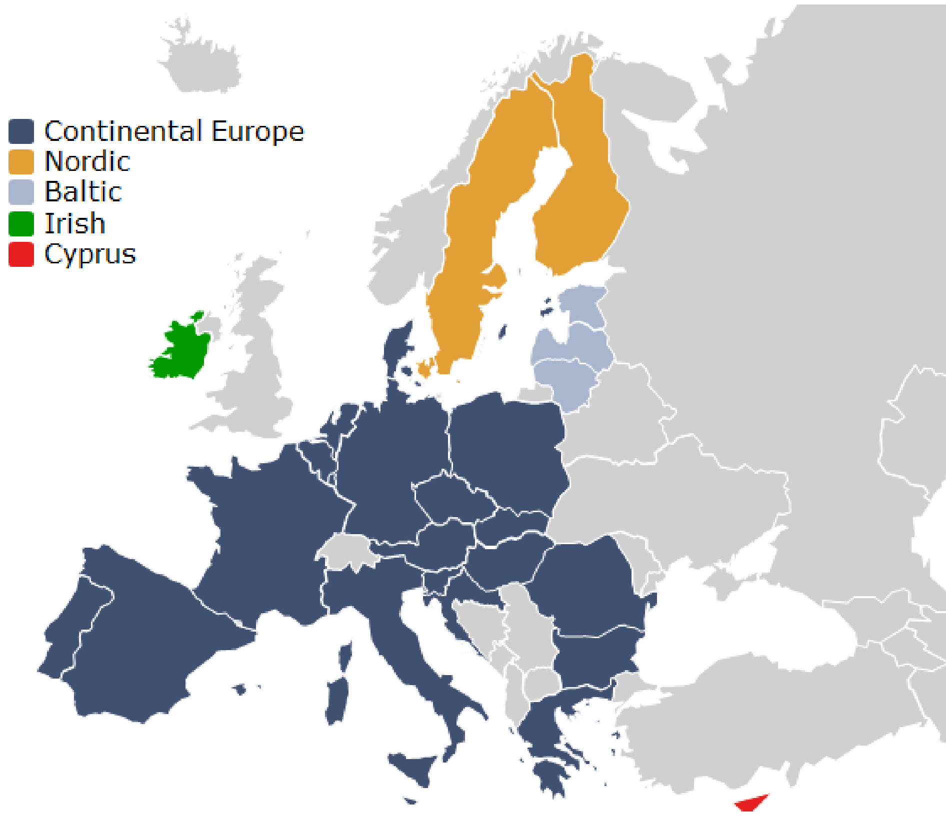
- **Predictability:** Solar and wind technologies are becoming increasingly predictable approaching the time of delivery, however both solar and wind are constrained by the accuracy and locational granularity of meteorological forecasting models.

System operation challenges of RES integration are mainly attributed to the stochastic and varying nature of the renewable energy sources, as well as the inherent uncontrollability of the input weather resources and the impossibility of storing them in their natural form. The following sections will explore the challenges of integrating renewables across three timeframes.

3.1.2.1 Real time stability

The EU27 members states are spread across multiple synchronised grids (see Figure 21). These separate EU synchronised grids transmit electrical power at a frequency of 50Hz. System operators (SO) are responsible for balancing frequency and preventing significant deviations which can result in load shedding, overloading, voltage collapse and/or blackouts.

Figure 21 EU27 synchronised grid areas

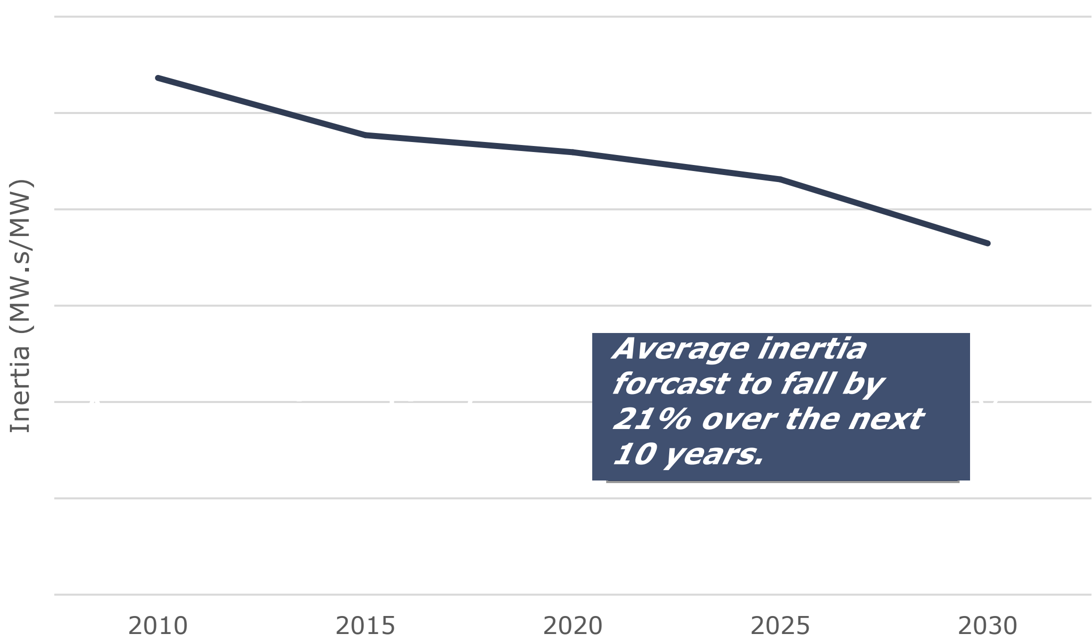


Source: AFRY Management Consulting

Conventional fossil fuel-fired generators are coupled to the grid and target a spin rate of 3,000 revolutions per minute (RPM) in order to maintain the standardised 50Hz grid frequency. The sum of their rotating mass (generators, engines and turbine rotors) contribute to system inertia, which is an essential component of maintaining real time stability of the power grid as it acts as an embedded buffer against rapid changes in frequency.

As increasing levels of non-synchronous renewables are connected to the EU electricity system, the average and minimum level of inertia on the grid will fall, and inversely to this, the rate of change of frequency (RoCoF) will increase in case of any imbalance between injections and withdrawals (see Figure 22).

Figure 22 Average inertia on total EU electricity system



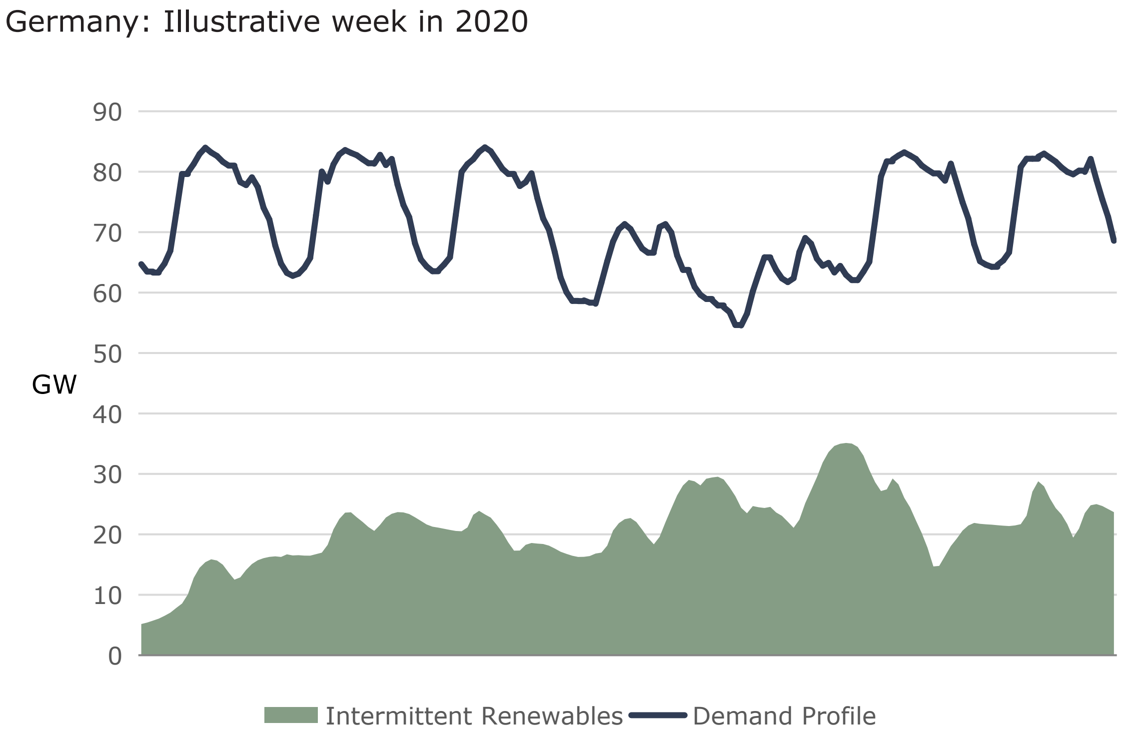
Note: MW.s/MW is an inertia constant that refers to the amount of inertia provided for each MW of capacity turned on.
Source: AFRY Management Consulting

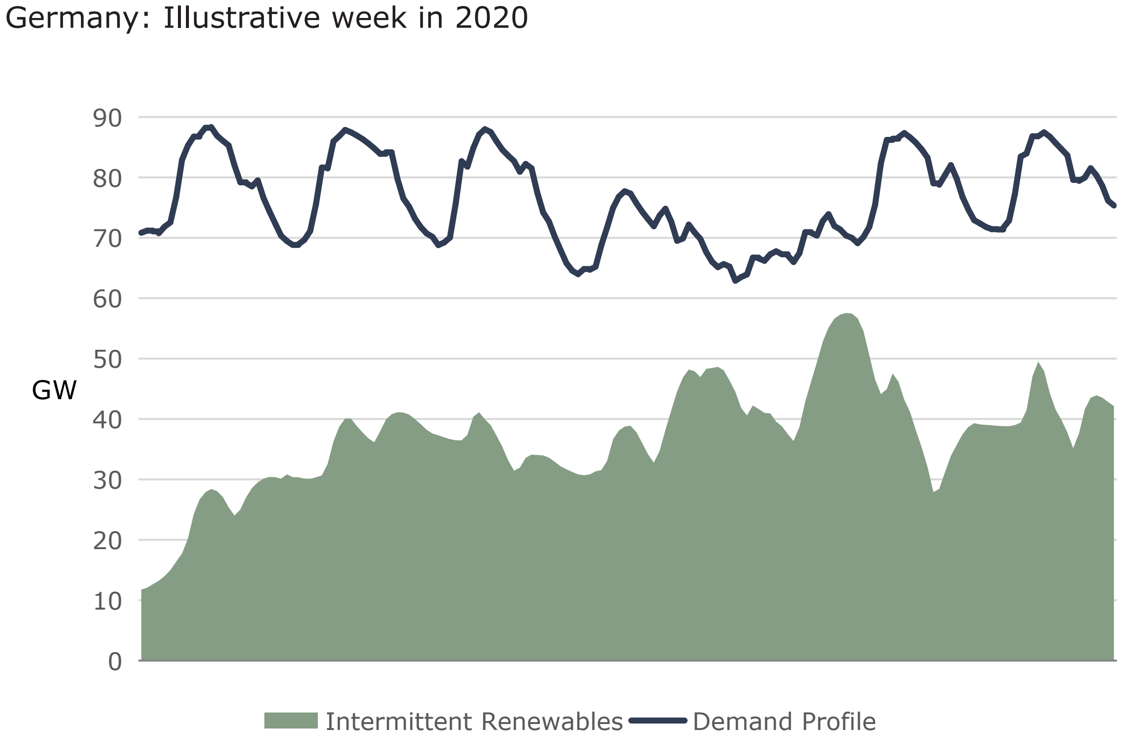
The growth of non-synchronised renewables is leading to falling levels of inertia, localised reactive power fluctuations and closure of centralised power plants capable of black start services. This is forcing European System Operators (SOs) to rethink their approach to procuring ancillary services in order to ensure real-time and continuous grid stability.

3.1.2.2 Daily balancing of intermittency

The challenge of matching daily supply and demand electricity profiles is magnified as the penetration of intermittent renewables across the EU increases in line with legislated targets. The stochastic nature of intermittent renewables will put pressure on controllable generation to satisfy the remaining demand requirements, also known as residual demand (see Figure 23).

Figure 23 Daily operation of the system in 2020 and 2030





Note: "Residual demand" refers to the difference between renewable generation and demand profile.
Source: AFRY Analysis

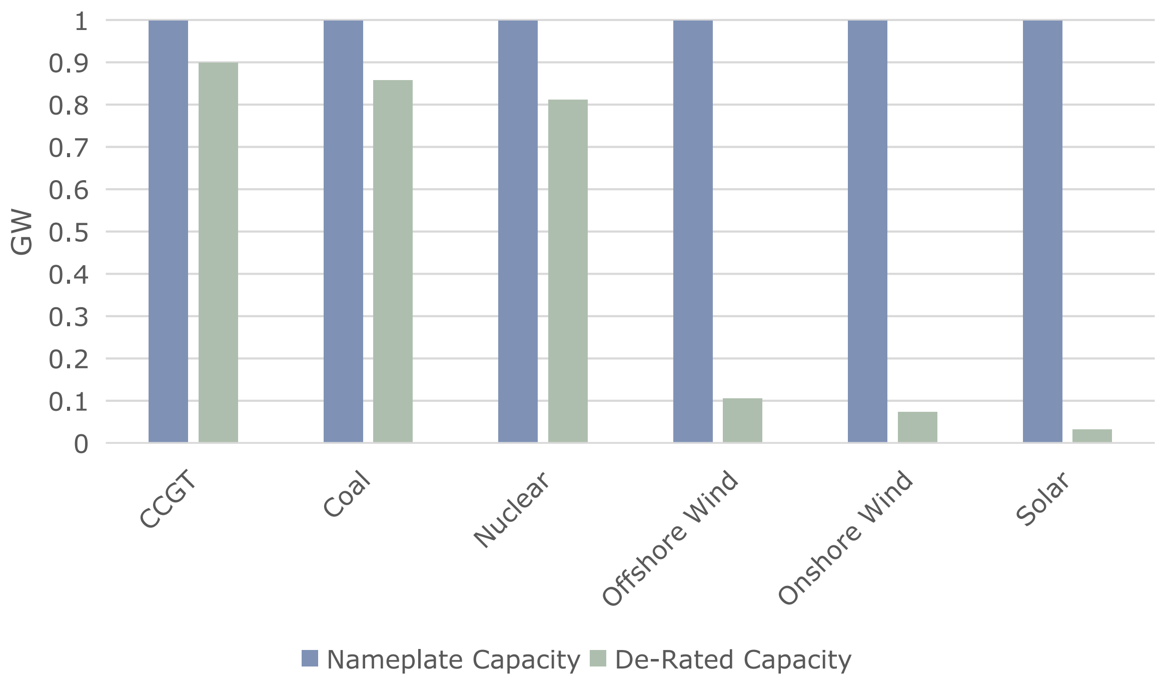
From a system operation perspective, more flexibility will be required in 2030 relative to 2020 in order to neutralise increasingly steep intraday ramp rates and balance higher levels of residual demand variability from one day to the next.

3.1.2.3 Safeguarding supply adequacy at peak demand

The issue of risk preparedness in the area of supply adequacy is a significant concern of the EU. Within the wider context of security of supply, EU regulations 2017/1485[6] and 2017/2196[7] constitute a detailed rulebook governing how transmission system operators and other relevant stakeholders should act and cooperate to ensure system security.

The non-dispatchable nature of wind and solar generation means that decarbonisation efforts often conflict with supply adequacy. De-rated capacity is a metric used to reflect the proportion of an electricity source which is likely to be technically available to generate at times of peak demand. Wind and solar offer minimal levels of de-rated capacity relative to conventional plant (see Figure 24):

Figure 24 Nameplate and de-rated capacity for technologies in GB



Note: Derating margins will vary across electricity markets based on local conditions – the data above is from the GB market.
Source: National Grid ESO Capacity Report

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6 European Commission, Establishing a guideline on electricity transmission system operation https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=OJ:L:2017:220:TOC

7 European Commission, Establishing a network code on electricity emergency and restoration https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=OJ:L:2017:312:TOC

- **Solar (winter peak market):** In Northern Europe, peak demand usually occurs in winter evenings; solar offers negligible de-rated capacity as there is minimal solar generation at this time.

- **Solar (solar peak market):** In Southern Europe, early deployment of solar often contributes to de-rated capacity if peak demand coincides with solar generation. However, additional deployment offers diminishing adequacy as the peak is shifted later in the evening, outside solar hours.

- **Wind:** The de-rated capacity of wind depends on whether it is onshore or offshore, the localised wind resource, the volume of wind capacity on the system and the spatial distribution of wind assets. However, even assuming these are all maximised, it is unlikely ever to exceed 15% of the total market.

The low short run costs of renewables have eroded the load factor and economics of conventional thermal plants. If fossil fuel-fired and nuclear plant are unable to recover their fixed costs they will inevitably close. However, their de-rated capacity is not guaranteed to be replaced if markets are left to their own devices – this is a risk that SOs often want to avoid.

3.1.3 Engaging the demand side

Prior to the development of an open market, the traditional power, heat and transport sectors largely operated independently from one another and energy flowed in one direction only, from distributors of fossil fuels to end customers. The guiding philosophy was to predict and provide for all of the customers' needs and preferences centrally. Many European markets have now progressed to an intermediate stage where new technologies are allowing increasingly responsive generation capacity close to demand sites.

There are a number of barriers to the integration of distributed generation/storage and responsive demand into a system coordinated by top-down centralised SO. These include:

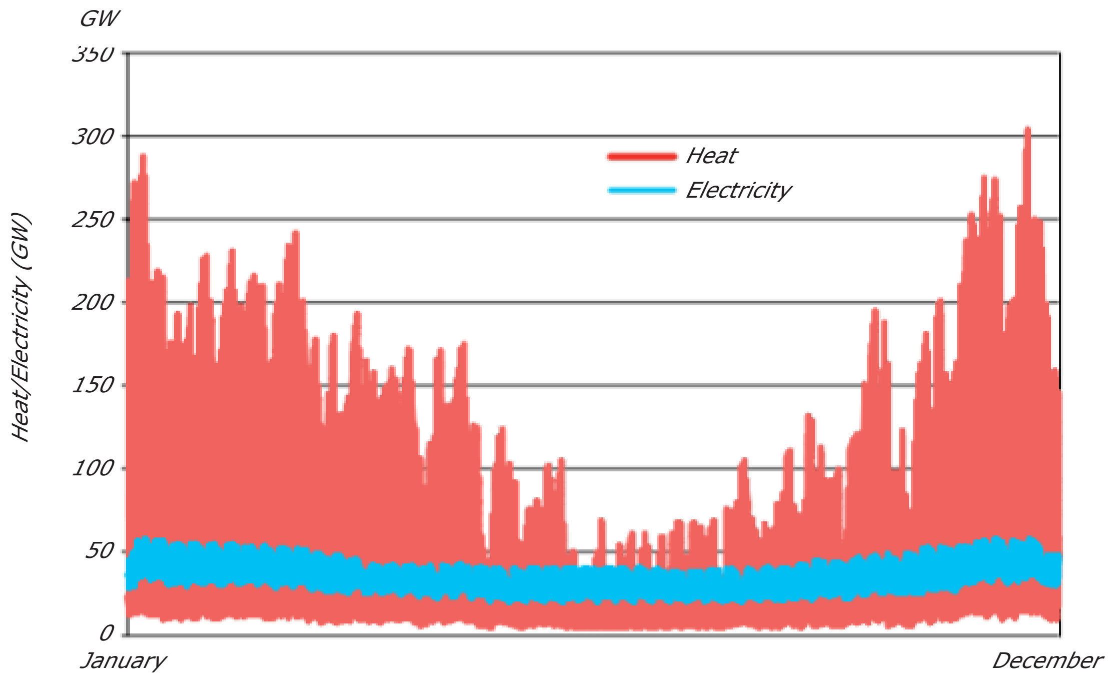
- **Technical:** Providing entry for DR participants to access full power market services will require technical and operational changes, such as deployment of smart metering technologies and developing increasingly sophisticated platforms for dispatching responsive demand.

- **Commercial:** Developing appropriate commercial Demand Response (DR) propositions which offer system value whilst incentivising customers to engage.

The promise of an increasingly smart and response demand side is substantiated by advancing ICT capabilities, the increasing adoption of smart meters, and an influx of innovative DR start-ups. Having said this, the majority of DR used today is relatively unsophisticated and largely restricted to energy-intensive industrial consumers who are offered financial incentives in return for accepting the possibility of their supply being interrupted, but with very little expectation that such response will actually be required. AFRY estimate that currently only 1-2% of global demand flexibility is able to directly respond to shortages or excess supply.

With today's expectations that zero-carbon generation will come predominantly from intermittent renewables, sectoral electrification is only compatible with decarbonisation if we embed flexibility in the newly electrified demand. A picture often used to demonstrate the impracticality of electrifying heat with no embedded flexibility, is a comparison of heat and electricity demand variability; a version of this is presented in Figure 25.

Figure 25 Comparison of heat and electricity demand variability



Note: The above heat and electricity demand is for the GB market.
Source: Imperial College via the Department of Energy and Climate Change (DECC,GB 2010)

The untapped DR potential is large, especially where space/water heating and vehicles are powered electrically; with increasing amounts of intermittent renewable generation, the value of DR is likely to further increase.

3.1.4 Electricity networks investment and operation challenges

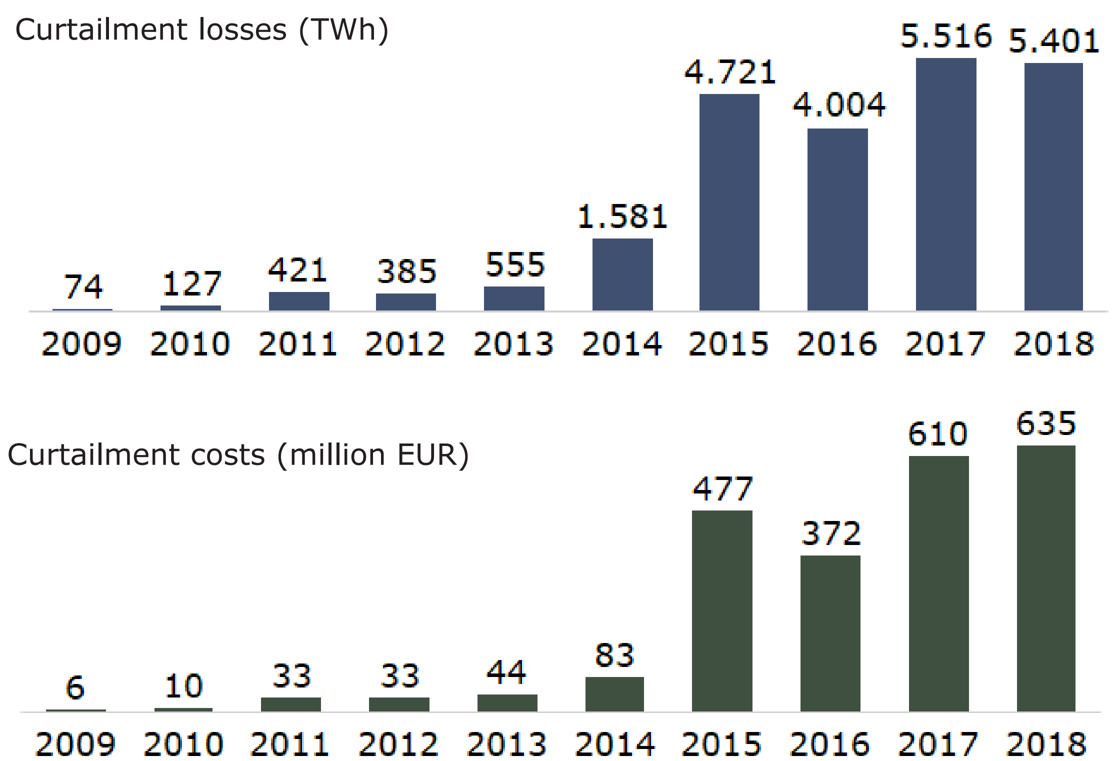
Historically, some EU countries have failed to effectively plan future grid infrastructure in conjunction with locations where renewable projects are likely to be sited. This can be explained in part by the lost economies of scale that took place during the restructuring of the industry that occurred in the 1990s-2000s. One key principle was the unbundling of generation and networks planning/operation. This coordination challenge is further exacerbated by long lead-times in network planning and grid expansion relative to generation capacity.

Deployment of renewables is largely driven by resource endowment and access to subsidy support, not grid constraints. This has resulted in considerable quantities of wind energy being sited in remote locations far from the centres of demand, with the majority of solar energy connected to the distribution network and behind the meter (BTM).

This has resulted in a number of issues affecting transmission and distribution networks, including:

- significant transmission network reinforcement costs, primarily associated with congested transmission lines during periods of high renewable generation;
- significant distribution network reinforcement costs, primarily associated with hosting large amounts of RES generation, often in localised areas;
- lack of clarity regarding the future role of TSOs and DSOs and coordination across network entities;
- increased levels of SO re-dispatching due to congested networks (see Figure 26).

Figure 26 Volume and cost of renewable curtailment in Germany from 2009 to 2018



Note: German re-dispatch has been particularly problematic due to insufficient transmission capacity connecting north and south. Regions such as the Nordics have experienced minimal re-dispatch requirements.
Source: BnetzA

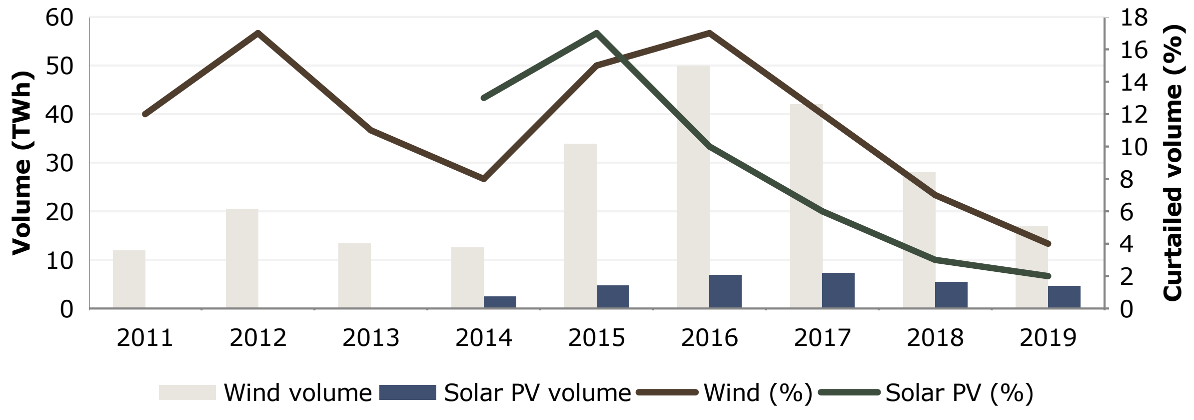
3.2 China

China's electricity system already experiences significant challenges in integrating intermittent renewable energy. This is the result of an inflexible planned market design paradigm which has yet to adapt to the short-term operational and pricing requirements of intermittent renewable energy generators.

Integration challenges are also closely linked to geography; China's best renewable energy resources are located in regions far from its major population and load centres, thus requiring significant transmission capacity to accommodate flows and consumption.

The effects of system and market inflexibility can be observed in recent curtailment statistics. This said, targets set out for the reduction of curtailment (down to 5% by 2020) have already been reached due to a host of active policies issued by energy planners.

Figure 27 Onshore wind and solar PV curtailment in China 2011-2019



Source: National Energy Administration, AFRY Analysis

As China works towards achieving the 2030 energy transition targets, regionally high proportions of renewable energy on the system could lead to an ongoing challenge to manage curtailment.

The 2030 electricity system will be more acutely exposed to weather effects, or intermittency, than that of today. A key challenge to address in the lead up to 2030 will be unlocking flexibility in the system. In order to handle the intermittency expected in 2030, system operators will need a range of resources in order to achieve system balance. These include more flexible thermal plants, grid-connected batteries, pumped hydro, interconnectors and demand side resources.

Existing markets and dispatch rules will not be fit for purpose in 2030. China's emerging competitive electricity markets are currently still in their early stages. While 'medium to long-term' (forward) markets have been rolled out across the country, these remain limited in terms of the number of products available, and market participation is [therefore] restricted. The deployment of flexible resources in the right timeframes, necessary for the integration of intermittent output, will require dispatch to be driven by market outcomes, ideally with trading taking place as close to real-time as possible.

At the time of writing, spot markets are being piloted in eight provinces, with additional markets to open up for pilots soon. Spot markets will be particularly important for the integration of intermittent renewables, and these will need to be rolled out widely in order to enable effective price setting in short timeframes and trading within and across provinces. In parallel, legacy planned electricity volumes will need to be eliminated to enable markets to reflect the supply and demand situation accurately.

Market integration across provinces is currently limited. While large volumes of electricity are at present transferred across provinces and grid regions, these are mostly determined by long-term government-regulated prices rather than markets. This system does not allow the short-term flexibility in pricing required to allow intermittent renewable energy generation to be effectively integrated across provinces.

Over the 2020s a key market design challenge will be the harmonisation of medium to long-term and spot markets, to enable trading to take place once integration happens. Market rules across both medium to long-term markets and spot markets will therefore need to undergo further revisions in order to enable trading to take place effectively between provinces.

As markets are introduced, wholesale electricity prices are expected to drop significantly, reducing gross margins especially for thermal coal plants which will most often be marginal generators.

As intermittent renewables are deployed more widely price cannibalisation effects are likely to impact marginal generators in particular. Additionally, increasing short-term price volatility will create a highly challenging market environment for non-flexible generators. This is likely to lead to a reversal of the current trend which includes continued investment in thermal coal assets in many regions across the country.

Distribution grids in some cities in China are also likely to become saturated with a high penetration of distributed PV capacities. This effect has been observed in Jiaxing, Zhejiang, where almost 80% of demand was met by distributed resources in 2018. In many distribution networks, especially in the East China Grid region, new distributed generation capacities are already facing restrictions due to claims of network saturation. The integration of more distributed renewable sources nationwide might face restrictions if the technical conditions are not in place.

At present, existing inter-regional and inter-provincial transmission capacities are often under-utilised: they are restricted due to operational constraints and therefore limited in their ability to ship the required volumes of renewable energy across the thousands of kilometres separating the west and east of the country. Transmission pricing regimes are also denting the economics of imported power. In 2030 new capacities will be necessary in order to integrate growing levels of intermittent renewables.

The current FiT mechanism may cause a range of market distortions as competitive markets are introduced. There are potentially more than 350 GW of renewable energy capacity falling under the fixed FiT. If these capacities are not exposed to market prices, there will be little incentive for them to respond to market signals. In renewable intensive regions, the lack of exposure could create significant balancing and cannibalisation price challenges for existing and future capacities.

Furthermore, the new Green Electricity Certificate presents opportunities and downsides for new investors as it does not afford revenue certainty. Generators may be exposed to market prices and imbalance risks, but without a fixed subsidy.

Incentivising the level of renewable deployment required to achieve decarbonisation targets may therefore require current and planned incentive schemes to be reconsidered over the course of the next decade.

4. SOLUTIONS TO OVERCOMING THESE CHALLENGES

In this section we will outline and explain the latest solutions being developed in European electricity markets to overcome the RES integration challenges outlined in the previous chapter. The drive to decarbonise will require markets to be redesigned such that they encourage investment in low-carbon technologies and enable new technologies while safeguarding security of supply and keeping costs for households and industry under control.

4.1 Renewable incentives

Recent trends for renewable support mechanisms have seen European countries move away from fixed subsidy payments. Most of the fixed FiT payments previously available have been phased out by governments, in favour of competitive auctions and contracts for difference (CfDs). This has allowed governments to incentivise new renewable capacity, whilst also managing the burden placed on budgets via such schemes.

A typical approach to competitive auction based subsidy schemes is to set a total budget for renewable support payments. This allows governments to manage the total expenditure on renewable subsidies. Renewable generators are then able to bid for contracts based not only on the level of support they need, but also on the amount of renewable energy that they can provide. This allows renewable energy to be procured at the most competitive cost, with resulting CfD strike prices ending at very competitive levels to date.

With renewables continuing to surpass expectations for achieving low prices in competitive subsidy auctions, it is likely that incentive schemes will continue to follow this trend in the immediate future. Whereas previous fixed payment FiT subsidies generally failed adequately to anticipate future cost reductions, subsidies given on the basis of competitive auction are better designed to respond to cost reductions.

As discussed in the previous chapter a degree of market risk exposure to the renewable generators is inherent to many of the more recent subsidy schemes, with a proportion of their revenues dependent on wholesale market prices. In order to incentivise further investment in renewables whilst also displaying budgetary responsibility, governments may need renewable investors to become accustomed to further exposure to market risks. This may include steps such as requiring them to better manage the imbalances that they are responsible for creating, by exposing renewable generators to imbalance costs.

Some investors in the EU are now sufficiently familiar with market risks that some renewable projects are likely to be built purely on a merchant or market price basis. It is as yet uncertain whether the volume of renewables that is desired could be delivered on this basis: while some investors are willing to build based purely on the wholesale price, it is more likely that in the longer term subsidy schemes are likely to evolve further.

Future subsidies could be designed to provide a mechanism to de-risk a project, without offering substantial material subsidy support. Rather than expecting renewables to be built on a merchant "subsidy-free" basis, offering "zero-subsidy" contracts that with a degree of revenue certainty could balance the wholesale market exposure. The direction of travel is towards lower value subsidies, which nevertheless offer some kind of de-risking to investors. Such support is likely to be necessary to continue to incentivise further investment in variable output renewables within a system dominated by the impacts of their intermittency.

4.2 Dealing with system operation challenges

As the volumes of intermittent renewable generation increase, greater emphasis will be placed on incentivising flexibility that can respond quickly to fluctuations in renewable output. As generation variability on the system increases, the amount of flexibility required at any given point in time is likely to be greater. However, it will also be more difficult to predict when the flexibility will be required. This in turn drives the need for flexibility to be available to the system at short notice. This has typically been the responsibility of system operators to manage, and the trend in the EU is for SOs to take more prominent roles as systems increase their share of variable renewables.

This is evident in a number of changes currently happening in the EU system. Firstly, the way that SOs ensure they have access to reserve capacity is changing. Secondly, capacity payments are being introduced to more and more markets to ensure enough capacity is available. Thirdly, greater emphasis is being placed on better use of flexibility across national borders. Each of these themes is considered in turn below.

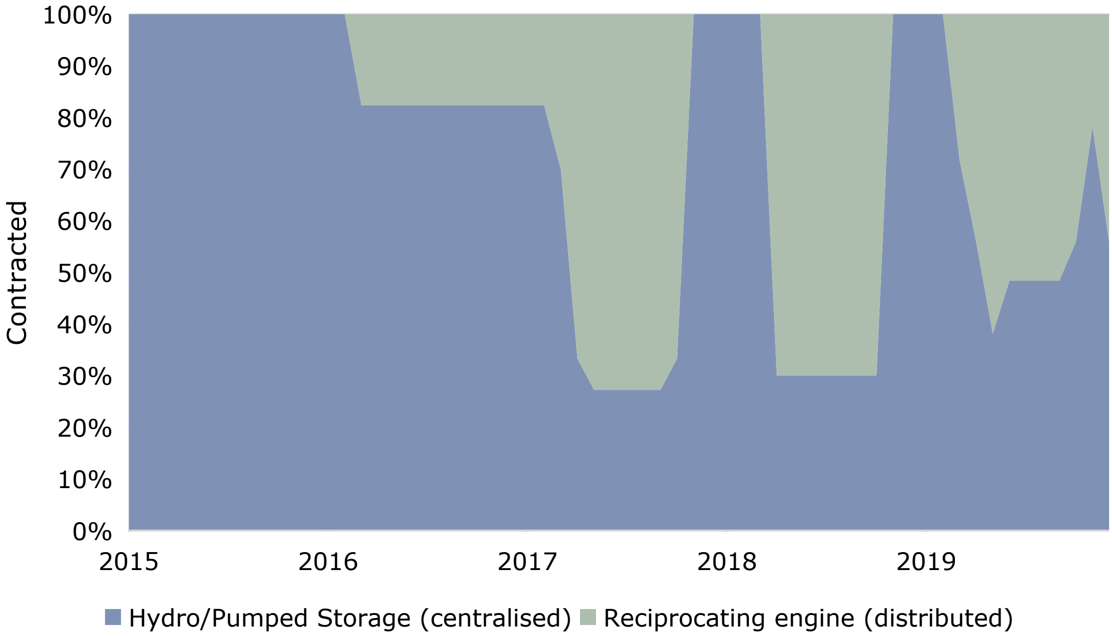
4.2.1 Real time stability - response and reserve

Reserve capacity is procured by system operators in order to ensure that the system continues to operate securely in the case of unexpected events such as plants unexpectedly breaking down or delivered output from renewable generators deviating from the amount forecast. Historically, these services were provided by thermal generators running below their maximum capacity, thus creating the option for the SO to instruct them to ramp up at short notice to cover any shortfall in generation and maintain the system balance.

The challenge to system operators with a system dominated by intermittent generation is that there is much less scope for thermal generators to be running, let alone running with capacity headroom sufficient to provide enough flexibility. Additionally, a more variable system means that greater reserve capacity is required in order to manage unexpected fluctuations in wind or solar output.

This has led SOs to seek flexibility from unconventional sources. This includes smaller scale generators, often connected to distribution networks, rather than larger traditional generators on the transmission networks. Figure 28 highlights an example of the trend for distributed reciprocating engines gradually to replace centralised hydro plants in offering responsive reserve services in Great Britain's ancillary market. The greater need for flexibility for system operators has created opportunities for flexible assets connected to lower voltage levels to offer the flexibility they need.

Figure 28 Fraction of successfully contracted fast reserve by technology type in GB from 2015 to 2019



Source: National Grid Fast Reserve

There have been a number of noteworthy consequences of this change:

- Shorter-term reserve services, procured closer to real time: Higher levels of flexibility are not always needed; on days of low renewable output, it is potentially inefficient to continue to procure services from flexible generators that could otherwise generate in the wholesale market. This has meant that procurement of reserves is moving away from long term contracts and towards shorter term products, procured closer to real time.

- The role and relationship of transmission and distribution SOs needs to be developed: For example, TSOs may look to procure flexibility provided by a resource connected to the distribution grid, while the distribution system operator may have a similar or opposing interest.

- Obtaining necessary volumes in smaller quantities from a higher number of providers requires operators to engage with digital solutions and new platforms: The flexible capacity providing reserve is typically now more distributed, and SOs will be given less visibility of the flexibility that will be available at any point in time. Digital solutions and new platforms will allow a wider variety of non-traditional flexibility 'aggregators' to offer their services.

4.2.2 Cross border trading and balancing

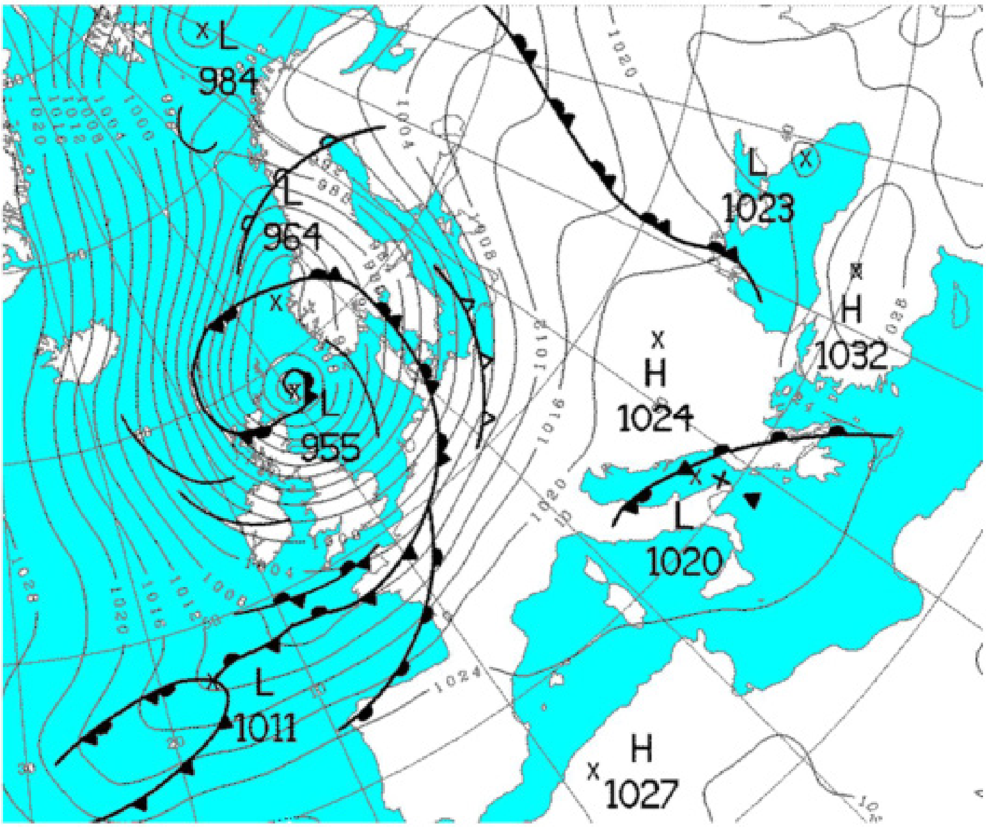
A key aspect of balancing intermittency has come in the form of greater cross border trading and balancing. The EU is becoming increasingly interconnected, with new High Voltage Direct Current (HVDC) cables and the reinforcement of AC transmission lines.

An example of the need for this can be seen from the weather map below (see Figure 29). This is a typical weather situation for the winter in Europe. A deep depression sits over north-west Europe, with very high wind speeds leading to high wind output. Great Britain, Belgium, the Netherlands and parts of Scandinavia would all achieve very high capacity factors for their wind farms in such weather. In a world of high renewable penetration, this would lead to excess production in these countries.

By contrast, many of the more southerly European countries have high pressure, characterised by still, and settled, cold weather. Italy and parts of Germany and France would have low wind output coupled with lower temperatures.

Greater transfer capacity across borders is necessary to ensure that the excess wind resources in northern Europe can adequately be transmitted to those regions where there could be a higher demand for power. A more intermittent system requires the ability to trade power across borders and utilise interconnection for ensuring the wider pan-EU system is efficiently balanced.

Figure 29 Pressure map during February 2008



Source: Met Office

Europe is undergoing a harmonisation of electricity-balancing rules in order to facilitate the exchange of balancing resources between European TSOs. The EC's Electricity Balancing Guideline[8] (EB GL) regulation lays down the rules for the integration of balancing markets in Europe, with the primary objective of enhancing Europe's security of supply.

The EB GL will be implemented across a number of projects. These include:

- **Project TERRE:** The Trans-European Replacement Reserves Exchange (TERRE) is the implementation project for the establishment of the European replacement reserve platform (RR-Platform).

- **Project PICASSO:** The Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation (PICASSO) is the implementation project for the establishment of a European platform for the exchange of balancing energy from frequency restoration reserves with automatic activation (aFRR-Platform).

- **Project MARI:** Manually Activated Reserves Initiative (MARI) is the European implementation project for the creation of a European platform for the exchange of balancing energy from frequency restoration reserves with manual activation (mFRR platform).

4.2.3 Ensuring supply adequacy with capacity remuneration mechanisms

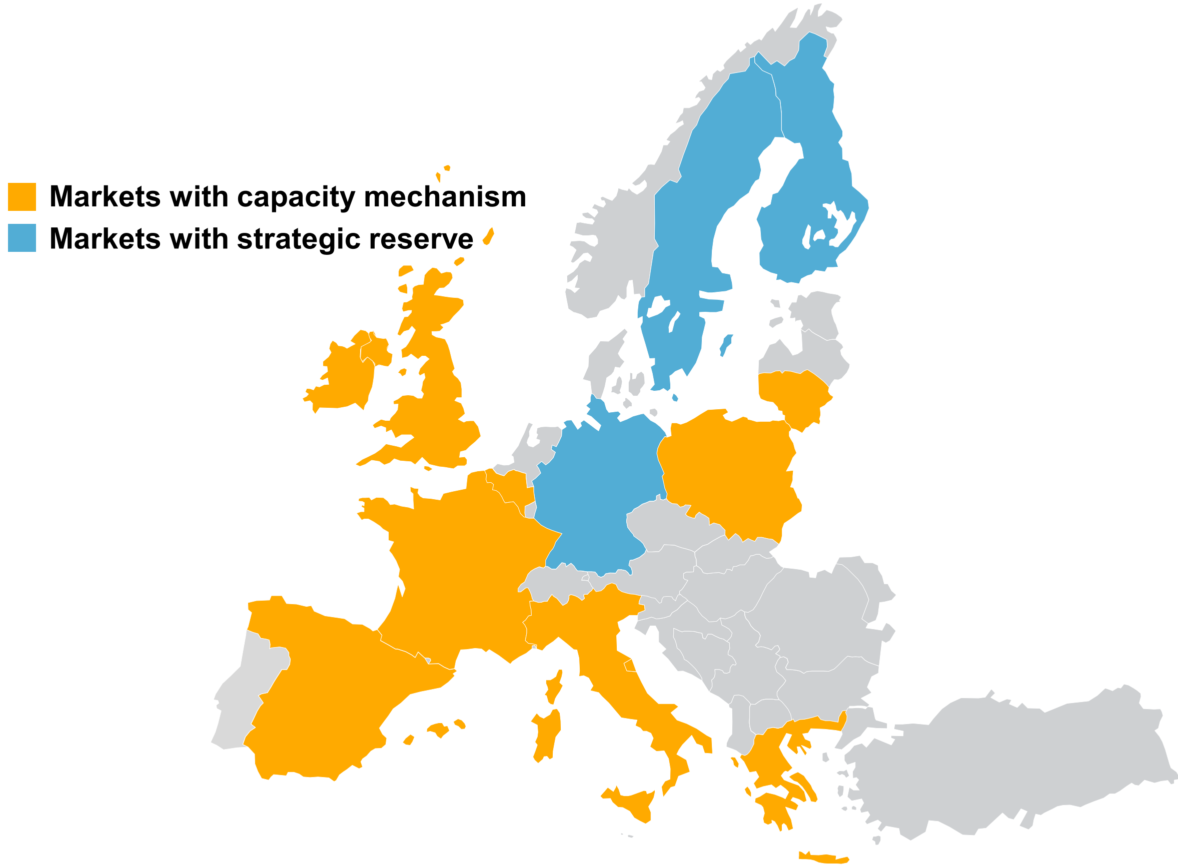
With more variable renewables, SOs have become increasingly concerned with the possibility of capacity shortfalls in periods of high demand and low renewable output. As explored in the previous chapter, renewables are eroding the volume of thermal generation and reducing the profitability of traditional thermal generators. However, SOs still have a responsibility to maintain adequate capacity margins to ensure demand can be satisfied.

The primary instrument used to maintain de-rated margins to date has been to offer generators so-called capacity payments. These reward generators for the amount of capacity that they can reliably make available at times of peak demand. Other markets have introduced strategic capacity reserves with some generators kept on the system purely for the times the system is stressed and at risk of capacity shortages.

Regardless of the specific designs of these capacity mechanisms, the aim is broadly similar across markets, namely that there is a need to incentivise capacity to stay on the system for the time that the variable renewables are unavailable. The represents a deviation from the general consensus 10-15 years ago, when many thought that energy-only markets were enough.

8 European Commission, Establishing a guideline on electricity balancing http://data.europa.eu/eli/reg/2017/2195/oj

Figure 30 Capacity remuneration across Europe



Source: AFRY Management Consulting

There is considerable debate about the effectiveness of capacity mechanisms as a means of dealing with the challenge of intermittency. Nevertheless, they have generally been deemed effective in procuring de-rerated capacity when considered purely on the basis of €/kW of available capacity.

4.2.3.1 Case study – Irish reliability option scheme

In the early consultation on the design of the new integrated single electricity market (the I-SEM), the option to discontinue capacity payments was considered. The SEM committee decided that to avoid the risk of generation shortfall some form of capacity payment should remain, but that in line with the EU integrated market, a more competitive process should be put in place with capacity payments through an auction.

Th Capacity Remuneration Mechanism (CRM) enacted uses Reliability Options (ROs), purchased in an annual uniform auction with two types of auctions planned: T-1 and T-4, referring to the auction being held one and four years before delivery, respectively.

A Reliability Option (RO) is a financial instrument that entitles the SO to receive a 'difference payment' from a generator if the price in the electricity market exceeds a pre-defined strike price (effectively €500/MWh). The load is subsequently hedged against high prices in the spot market.

During the auction process, the state transmission operator EirGrid establishes how much capacity is needed to secure adequate supply, then purchases the requisite amount of ROs to cover that capacity in an auction. The auction clears at the minimum price that is needed to procure the desired amount of RO capacity.

4.3 Engaging the demand side

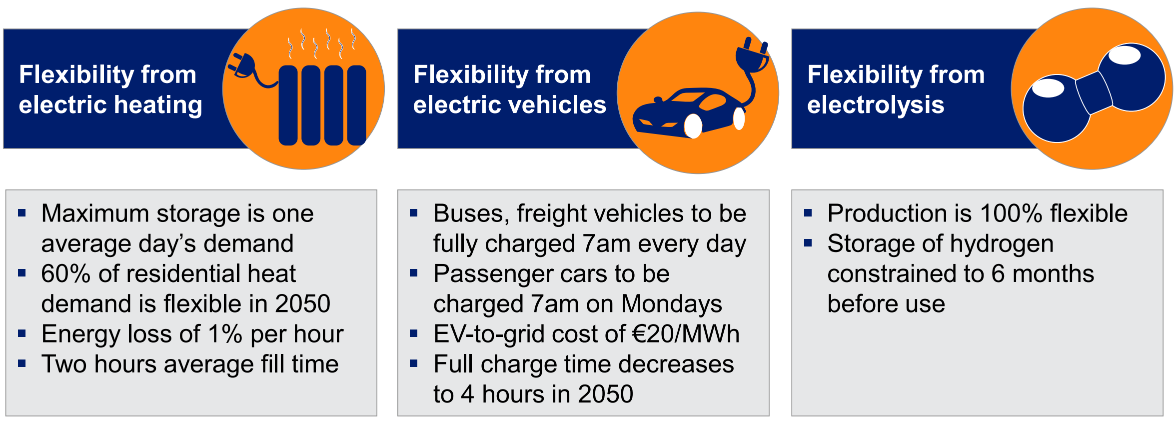
The delivery of a high renewable generation mix will represent a significant departure from the status quo, which can be crudely characterised as being a market dominated by load-following generation with a relatively predictable pattern of demand and limited opportunity for demand-shifting.

In contrast, the implications of a move towards a system with a high proportion of renewables are that:

- the electricity generation sector could become more inflexible, which places a greater premium on having load that can follow generation;
- electricity demand could be more variable, increasing the benefits of shifting load away from peak periods; and
- electricity demand may have much greater potential for flexibility through the storage associated with heat, transport, and electrolysis (see Figure 31).

Therefore, there would be clear benefits to the implementation of demand-side flexibility in helping to deliver a low-carbon, affordable and secure electricity supply.

Figure 31 potential flexibility from electricity demand in 2050



Source: AFRY Management Consulting

However, demand-side flexibility is one instrument trying to meet two policy objectives – tracking generation, especially wind, in order to take maximum benefit from zero fuel cost generation (and reduce other generation costs), but also flattening load in order to minimise network investment. This secondary objective is also important when considering that renewable resources will increasingly be located further away from demand centres, where more land is available, and the wind resources are better.

Initiatives to enable DSR providers to find routes to market and to find value in the flexibility they offer will become increasingly important in order to match the increasing inflexibility of intermittent renewables.

4.4 Incentivising efficient investment

Market redesigns and charging regimes will need to evolve in order to enable the appropriate level of investment in wider network infrastructure and across generation assets. Markets that enable the energy transition must deliver credible signals in operational timeframes and investment timeframes. This will require fair and balanced value attributed across the five C's:

- Commodity: value of energy.
- Capacity: value of reliability or availability.
- Capability: value of flexibility (e.g. response speeds).
- Congestion: value of easing network congestion or offsetting network investment.
- Carbon: value of low carbon generation (avoided carbon emissions).

4.4.1 Investment in network infrastructure

As examined in the previous chapter, historically some countries in the EU have not taken potential sites of renewable projects into account when planning future grid infrastructure.

Locational and capacity dynamic price signals for new investment will help to incentivise new renewable capacity to be closer to demand and more widely dispersed. This will likely require central planning in order to identify favourable zones that reflect the costs of grid infrastructure relative to more distant locations which create congestion.

In addition to this, improvements could be made in planning future grid infrastructure requirements well in advance, particularly to locations where a large number of projects are likely to be sited. While many countries do this to some extent e.g. Germany and the UK, this could be more proactive and forward looking to avoid problems before they arise. The UK currently has a transmission network expansion planned which, had it been done earlier, would have reduced curtailment on the existing system.

5. SUGGESTIONS FOR CHINA

As China sets out to put in place targets and plans under the 14th Five Year Plan (2021-2025) and new policies to further reform electricity markets, an opportunity exists to design markets and policies that will be adapted to the decarbonised, decentralised and digital electricity system of the future.

In this section we make a number of suggestions, drawing on the latest thinking in European market design.

5.1 Renewable support schemes

In order to achieve a high proportion of renewable energy in the 2030 (and then 2050) electricity supply, regulators will need to consider how to incentivise continued large-scale investment in renewable energy capacities.

While renewable energy technologies have experienced significant cost reductions in recent years, materially reducing the difference in levelised costs with conventional technologies, their high capital-low operating cost structures mean that investments in renewables still require mechanisms to manage price and volume risks. The current FiT scheme addresses price risk by affording a fixed rate for 20 years. Moving forward, however, the proposed GEC provides less price certainty.

In addition, volume risk is not addressed under the current scheme, which does not compensate for curtailment, and does not address intermittency. Guaranteed purchase does address this issue, though challenges persist in its implementation due to continued hour allocation planning in the market. This should be done alongside the roll-out of longer-term contracts (current forward contract being limited to monthly or annual contracts). Exposure to markets should also come with responsibility, and therefore renewables should also be exposed to imbalance costs, incentivising renewable resources to be deployed with consideration of system stability.

However, if renewables participate directly in wholesale markets this could lead to price cannibalisation effects, as has already been observed in Germany and other markets. While this volatility may initially be cause for concern, it will also be an opportunity for other sources of flexibility to secure revenues in the market (e.g. grid connected batteries, demand side resources etc.), the growth of which is expected in turn to reduce volatility.

Any future subsidy mechanism design could address price risk by offering financial contracts (such as Contracts for Difference), with competitive auctions to set subsidy levels. These have been shown to incentivise investment by offering revenue predictability, while at the same time resulting in zero or near-zero subsidy commitments.

In the lead up to 2030, in order to ensure renewable output is consumed, the current rules around the Renewable Portfolio Standard should be clarified soon, and clear responsibilities for target achievement should be communicated to electricity suppliers and consumers. In addition, Portfolio Standard calculation methodologies should be made public so that investors can project their own GEC price levels and make long-term investment decisions.

5.2 Electricity market design

Alongside new subsidy mechanisms, China's future electricity market design should address renewable energy integration and should incentivise flexibility.

We highlight the importance of rapidly implementing market reforms, and in particular introducing spot markets with dispatch rules aligned to market outcomes with a parallel roll-back of generation planning.

Spot markets should be technology neutral, allowing renewables, batteries, and demand side resources to play a role, and should allow for continuous trading up until (as close to as possible) real-time. This will assist in integrating renewables by allowing intermittent generators to refine their market position as output patterns become more certain in intraday market timeframes. Continuous trading, in turn, will allow for a diversity of technologies to access revenues in the market across a range of different timeframes, promoting the optimal deployment of existing resources.

In addition, these markets should reflect the value of scarcity. Current price caps and floors proposed in spot market pilots will hinder the deployment of flexible capacities, as these represent revenue streams for flexibility providers. While concerns of price volatility are justified, should flexibility providers be enabled to take advantage of these they are likely to, by the same token, reduce volatility. These flexibility providers include (among others) grid connected batteries, flexible thermal plants, interconnectors, pumped storage and demand side resources such as large power consumers and electric vehicles.

A participative demand-side represents a particularly important opportunity for increasing the system's flexibility. Future market designs should consider the integration of multiple demand resources into electricity markets, enabling demand to follow an increasingly intermittent supply side, and therefore helping to balance the system and reduce price volatility. Barriers to market entry for aggregators should be lowered by simplifying aggregator requirements. The ongoing distribution network deployment and retail market reforms should be accelerated as part of this.

Similarly, flexibility providers – including potentially more flexible thermal assets – will benefit from the rapid roll-out of ancillary service markets alongside spot markets. Under new ancillary service markets, products should enable the short-term procurement of reserves in order to reflect the short-term operational requirements of an increasingly intermittent supply side. With access to revenue streams in ancillary service markets and spot markets, flexibility providers will therefore be able to stack revenues, further strengthening the investment case for crucial assets.

As distributed wind and solar PV capacities grow, markets will need to adapt to reflect increasingly local operational requirements. Nodal pricing or well-defined price zones within provinces will enable these changing dynamics to be better reflected in electricity pricing, although alongside these should come hedging mechanisms such as Financial Transmission Rights and long-term bilateral contracts to enable investor confidence.

Distribution network operators will need to integrate digital technologies and play an increasingly active role, as the distribution level becomes increasingly challenging for the transmission system to perceive or manage. The improved integration of distributed technologies will require reserves and adequacy to be considered on a more granular level. Markets in 2030 may seek to consider decentralised procurement of system adequacy.

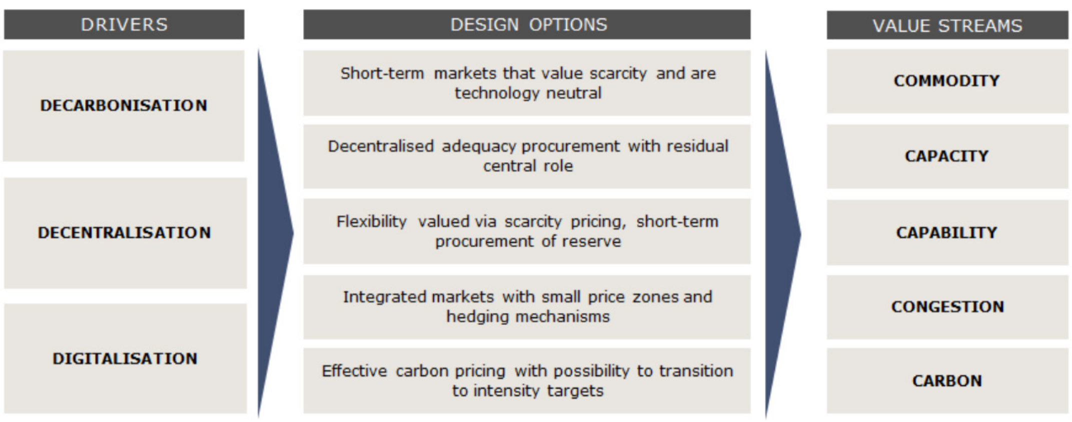
Markets should also be integrated. The European experience has shown that market coupling can help to increase opportunities for renewable integration by allowing generators to meet demand in other countries. In parallel, market coupling has helped to reduce the costs of developing and maintaining the electricity system across the Single Electricity Market. The same principles apply in China.

As markets are integrated at regional and national level, market rules should be harmonised in order to allow electricity prices across provincial markets to be reflective of the same commodity. Market coupling in China is likely to be an enabler of renewable energy integration, while at the same time reducing provincial market power hurdles and making the most efficient use of existing generation capacities. Alongside market coupling the expansion of existing interconnector capacities, Ultra-High Voltage (UHV) AC and DC, should be considered. With efficient market prices and appropriate transmission charging regimes, grid planners will be better positioned to determine the economic viability of new interconnector projects.

Finally, market designs should consider appropriate carbon pricing. As subsidies for renewables are rolled back appropriate carbon pricing will assist in enabling subsidy-free, or merchant, renewables to come forward as these will be increasingly cheap relative to fossil-fuel generators.

We summarise the above market design suggestions in Figure 32 below.

Figure 32 Selected market design options for renewable energy integration



Source: AFRY Analysis

6. SUGGESTIONS FOR THE EUROPE-CHINA ENERGY COLLABORATION PLATFORM

In the scope of this paper, we have additionally been posed the question: where should the Europe-China Energy Collaboration Platform (ECECP) focus its attention in future collaborative activities?

The authors of this paper offer the following suggestions to the ECECP for their consideration moving forward.

There exist a number of similarities between the European and the Chinese electricity systems, particularly in terms of the future challenges to be faced due to an increasingly decarbonised, decentralised and digital electricity system.

In parallel, many of the solutions to the challenges are common ones. We therefore highlight system flexibility as a key issue for exchanges.

System flexibility is fundamental to overcome the challenges of an increasingly intermittent electricity system. No full set of solutions currently exists, and it therefore offers opportunities for mutually beneficial learning.

Areas to explore for future collaboration could include exchanges on market design and market mechanisms enabling the deployment of these resources.

These include, for example, flexible thermal plants, grid-connected batteries, interconnection, and demand side resources - such as consumer demand response, virtual power plants, grid-interactive electric vehicles and behind-the-meter batteries.

In addition, the Platform could engage in exchanges on the evolving role of distribution networks and local energy markets.

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