Meeting Power System Flexibility Needs in China by 2030

A market-based policy toolkit for the 15th Five-Year Plan

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Abstract

The People's Republic of China is deploying record levels of wind and solar PV, challenging the flexibility of its power system. At the same time, China has been making big steps towards implementing markets, and the goals announced in 2020 of carbon dioxide emissions peaking before 2030 and carbon neutrality before 2060 have added momentum to expand their footprint.

This report investigates the evolving flexibility requirements of China's power system as it transitions towards a cleaner energy mix. The analysis aims to present a market-based policy toolkit that can enhance flexibility, especially during the 15th Five-Year Plan period (2026-2030), focusing on short-term flexibility solutions for the integration of variable renewable energy.

Though the main audience of this report is policy makers in China and experts from around the world intending to contribute to power sector reforms, the report also aims to be informative for generalist readers.

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Table of contents

Executive summary

China's rapid wind and solar PV deployment is driving an increasing need for system flexibility

The rapid wind and solar PV growth is driving an urgent need for system flexibility in the People's Republic of China (hereafter, "China"). China's power system is undergoing a profound transformation, spurred by a sharp increase in variable renewable energy (VRE) capacity and the electrification of various sectors. Between 2022 and 2030, short-term flexibility for daily operations – characterised by hourly and daily ramping requirements – is expected to triple, primarily due to the rapid expansion of solar PV.

Power sector reforms are accelerating the deployment of market-based mechanisms. Reforms since 2015 have been giving markets a growing role. Over the past 12 months, there have been notable achievements, such as the official launch of four provincial spot markets and the inter-provincial spot market. In 2022, the National Development and Reform Commission's Document No. 118 pushed for the establishment of a unified national power market system, incentivising market integration across provinces and regions.

Well-designed power market reforms are critical to unlocking flexibility and meeting 2030 energy targets. As China transitions to a market-based power system, power markets need to be designed to prioritise flexibility and deployed in a co-ordinated way. If China is to meet its objective to peak carbon emissions before 2030, non-fossil resources such as hydropower, battery storage and demand response could fulfil nearly 60% of the short-term flexibility needs in 2030, enabled by well-functioning spot and ancillary services markets. A unified national power market system will also unlock system-wide flexibility, enabling efficient resource sharing across provinces and regions. Delays in market implementation could prolong reliance on thermal plants, jeopardising progress towards a more sustainable energy system.

The 15th Five-Year Plan (2026-2030) presents a pivotal opportunity for China to implement critical power market reforms. This period is crucial for China to solidify its commitment to reforms that support system flexibility and enable the integration of vast amounts of VRE. Achieving this transformation while maintaining grid stability and reliability will require a paradigm shift towards planning and operating practices centred around markets and flexibility.

Market reforms are needed to ensure that China meets its flexibility needs in 2030 and stays on track with its climate goals

Market designs must provide effective price signals to incentivise flexibility. Currently, over 90% of traded electricity in China is tied up in medium- to long-term (MLT) contracts, which fix prices and volumes over extended periods, preventing adjustments that reflect real-time system needs. The underdevelopment of spot and ancillary services markets in many provinces and regions further hampers flexibility, limiting incentives to respond to changing system conditions.

Most of the needed flexibility can be unlocked through improvements to the dispatching practices. Implementing efficient economic dispatch at the provincial and regional levels yields the most substantial gains in flexibility and VRE integration. By developing and expanding spot markets with the right design features, economic dispatch prioritises the use of resources based on their marginal cost, ensuring cost-effective power system operation.

Regulatory reforms should focus on harmonising policy frameworks and expanding market participation. Requirements and rewards for provision of flexibility often differ across provinces and regions, creating barriers to entry for flexibility providers and hindering the scalability of solutions. New and smaller players face restricted access to markets, reducing competition and innovation. By facilitating inter-provincial market access and better integrating inter-provincial trade into provincial systems, China can broaden its flexibility base and enhance cross-regional cooperation.

Expanding and optimising the use of infrastructure is essential to achieve a national market system. China's inter-provincial and distribution grid infrastructure is falling behind the requirements of a flexible and modern power system. Underutilised battery storage assets highlight the misalignment between flexibility needs and the business models for these assets. This underscores the importance of scaling up the necessary infrastructure, including grids and digital technologies, to align with China's decarbonisation goals.

Reforms should accompany coal plants in their transition from energy suppliers to providers of flexibility services. While coal plants will continue to play a key role in providing grid stability and flexibility, their contribution in terms of electricity generation will have to decline. This shift requires targeted policies that support coal plants in becoming providers of system services, such as frequency regulation and ramping support, and seasonal flexibility, to ensure a smooth transition towards a more flexible and low-carbon power system.

A policy toolkit for the 15th Five-Year Plan to unlock flexibility through power markets

	Maximise flexibility potential	Boost deployment of new flexible resources	Optimise resource sharing nationwide
MLT markets	Increase temporal granularity of physical contracts; Increase price range fluctuation	Lift inflexibilities in contract design; Promote the use of financial contracts	Open interprovincial trade to market participants, besides grid companies
Spot markets	Trade closer to real time and shorten settlement periods; Advance economic dispatch	Advance economic dispatch; Maximise participation; Remove barriers to new energy and VPPs	Better connect interprovincial and provincial spot markets
Ancillary services markets	Deploy mechanisms for dedicated services where necessary; Implement market-based price mechanisms	Implement market-based price mechanisms; Remove barriers to new energy and VPPs	Unify markets and products nationwide; Promote interprovincial trading of reserves
Capacity markets	Introduce minimum flexibility requirements; Remunerate based on performance	Select assets competitively; Remunerate based on performance; Remove barriers to new energy and VPPs	
Retail markets	Incentivise contracts linked to spot market prices for large consumers; Promote TOU for households	Increase TOU peak-to-valley ratio; Deploy smart metering and promote system-friendly self-consumption	
Grids	Implement time-varying network charges	Improve transparency of grid availability for future projects	Remunerate grid capacity instead of usage rate; Harmonise grid connection rules, promote flexible connections and predictable curtailment frameworks
Planning and market unification	Mandate flexibility assessments in planning and develop tools to support this exercise	Articulate planning around markets and soften administrative measures as markets are implemented	Advance national and provincial markets integration; Harmonise grid connection rules, promote flexible connections and predictable curtailment frameworks

A policy toolkit for the 15th Five-Year Plan can unlock flexibility at the regional and national levels

China urgently needs a comprehensive policy toolkit to address its growing flexibility challenges and manage the complexity of its power sector. Identifying the right reforms is not easy, given the sector's coverage of a vast geography, diverse climate zones and the varying levels of VRE penetration across regions. Different areas face unique challenges, requiring tailored policies based on local conditions while co-ordinating reforms across key market segments, including MLT contracts, spot markets, ancillary services and capacity remuneration mechanisms. Without a unified, carefully targeted strategy, fragmented development could prevent China from achieving system-wide flexibility.

The toolkit provides a practical framework with tailored recommendations for achieving flexibility by 2030. Recommendations cover all market segments, ensuring each market fulfils its primary function without interfering negatively with other areas. The toolkit also supports provincial and regional implementation, helping provinces and regions prioritise reforms based on the VRE penetration levels and the maturity of their spot market.

Strong governance and institutional capacity will be crucial for the successful implementation of the policy toolkit. While the toolkit outlines necessary reforms for flexibility, the broader success will depend on a robust governance framework, institutional capacity and a commitment to ambitious reforms. With firm regulatory support, China can ensure that the toolkit helps meet its climate and energy goals while securing a reliable, efficient and sustainable power system.

Background and motivation

A transforming power sector landscape

In July 2024, the People's Republic of China reached a significant milestone in its clean energy transition, surpassing 1 200 GW of wind and solar PV capacity – six years ahead of its target. The IEA projects this figure will rise to 4 232 GW by 2030, contributing 39% of the country's electricity generation, up from 15% in 2023. This rapid growth presents new challenges, particularly concerning system flexibility. As variable renewable energy (VRE) expands, balancing the grid to accommodate fluctuating supply and demand is becoming increasingly difficult. On the demand side, the electricity share in final energy consumption had risen at a record pace, from 11% in 2000 to about 28% in 2023, driven in large part by electrification of heating and cooling in the building sectors. This trend is set to continue with the rapid uptake of EVs.

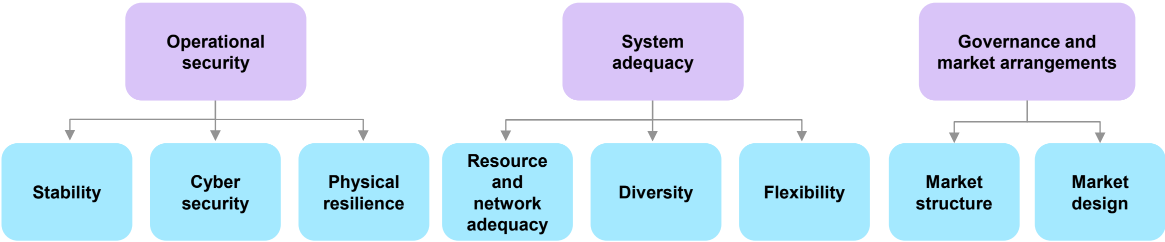
In this context, the government issued new guiding opinions in early 2024 to co-ordinate and optimise the deployment and use of flexibility resources, especially through market-driven mechanisms. While significant progress has been made on the technological side – such as coal plant retrofits, battery storage and ultra-high voltage (UHV) transmission – advancements in power markets and regulatory frameworks are crucial to convert these record-breaking renewable installations into the actual decarbonisation of its power system.

With the rapid deployment of wind and solar, China's power system is undergoing a significant transformation, requiring substantial adjustments by 2030. This transformation will be even more pronounced in regions with abundant renewable energy resources. As the share of wind and solar increases, the impact on the power system is initially manageable through incremental policy adjustments. However, as China continues to deploy VRE at a high pace, a fundamental shift in power system planning, operation, and financing will be required to efficiently integrate higher levels of wind and solar.

Flexibility as a cornerstone of electricity security

Electricity security refers to the system's ability to ensure an uninterrupted supply of electricity while withstanding and recovering from disturbances. It encompasses various elements, including stability, adequacy and resilience against both cyber and physical disruptions, including those caused by climate events. Flexibility is critical to electricity security as a key enabler of adequacy, providing the system with the ability to maintain a continuous balance between electricity supply and demand, even during unexpected disruptions. This ability is essential for maintaining grid stability and preventing large-scale failures.

Multiple dimensions of electricity security



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There is no internationally standardised definition of power system flexibility. Different organisations such as the IEA, RMI and North China Electric Power University, apply varying definitions, time scales and assessment methods. However, a common approach is to categorise flexibility across different time scales, with the ramping rates of net load often used to illustrate system flexibility at each time scale. The IEA defines power system flexibility as the ability of a power system to reliably and cost-effectively manage the variability and uncertainty of supply and demand across all relevant timescales.

Affordability is another crucial dimension of electricity security, particularly in the context of energy transitions. Electricity prices are affected by factors such as fuel costs, grid infrastructure investments and the costs associated with flexibility. Well-designed electricity markets can help manage these costs and ensure affordability by providing accurate price signals, promoting competition and incentivising flexibility on the supply and demand sides.

Towards a national system of markets in China

Since the 2002 power sector reform (Document No. 5), China has been transitioning from a centrally planned system to one driven by market mechanisms. The 2015 reform (Document No. 9) marked a turning point by encouraging power markets to improve generation efficiency and adapt to the evolving power landscape. This reform granted provinces autonomy in designing and implementing market pilots tailored to local conditions. Recognising the need for co-ordination, Document No. 118 in 2022 set out a strategy for establishing a unified national power market system by 2030. While not requiring harmonisation of the existing market designs, the strategy prioritises co-ordination and expansion of inter-provincial and regional trade.

Given the complexities of full market integration, the IEA previously proposed adopting secondary market models as a pragmatic approach. These models enable local markets to retain autonomy while quickly capturing the benefits of regional co-ordination, for example by creating a national market for trading surplus generation or optimising power flows between regions.

Addressing China's flexibility needs over the next Five-Year Plan

China's power sector reforms demonstrate the importance of pacing and carefully selecting market mechanisms to balance affordability, security and decarbonisation. In the 15th Five-Year Plan (FYP) period from 2026 to 2030, a comprehensive approach will be needed to address the flexibility challenges of a fast-transforming power system and meet its climate and energy goals. This approach will require infrastructure upgrades, such as smart grids and energy storage, as well as investments in energy efficiency, advanced forecasting tools and market reforms that value and incentivise flexibility services.

Structure of the report

This report provides policy recommendations for system flexibility applicable in the timeframe of China's 15th Five-Year Plan (2026–2030) and evaluates the flexibility needs of China's power system, with a particular focus on how power markets can unlock flexibility.

Chapter 1 offers a comprehensive assessment of flexibility in China, using the IEA's Regional Power System model to quantify how supply- and demand-side resources can meet flexibility needs by 2030, assuming appropriate market mechanisms are in place. The chapter explores policy barriers that currently limit flexibility.

Chapter 2 examines power market reforms, highlighting those most effective at unlocking flexibility. Model scenarios contrast an optimistic outlook with alternatives where slow reforms hinder progress. The chapter emphasises the significance of rapid market developments in achieving dual carbon goals and meeting the corresponding flexibility needs.

Building on these findings, **Chapter 3** presents a policy toolkit for the pertinent sections of the 15th Five-Year Plan, outlining steps for conducting flexibility assessments, identifying key policies and monitoring the system's evolving flexibility needs. The chapter also includes recommendations for applying the toolkit at the provincial or regional level, accounting for the diversity of China's provinces and regions.

The **Annex** provides further details on the modelling methodology.

Chapter 1. Power system flexibility in China

The growing need for flexibility

China's power system is undergoing a rapid transformation, driven by the large-scale deployment of variable renewable energy (VRE) on the supply side and the electrification of end uses like industry, space heating and road transport on the demand side. The increased variability in supply and demand arising from these assets makes flexibility a cornerstone of power system security and the energy transition.

Despite the rapid evolution of China's power system and concerns over electricity security, there is currently no official quantification or regular assessment of system flexibility needs across its provinces and regions. This gap leaves uncertainty regarding the resources required to meet current and future system needs, possibly leading to over-investment or poor use of available assets.

This chapter examines the flexibility needs of China's power system, the current state of flexibility resources and the barriers – particularly market and regulatory – that hinder their expansion.

Evolving approaches to address growing flexibility needs

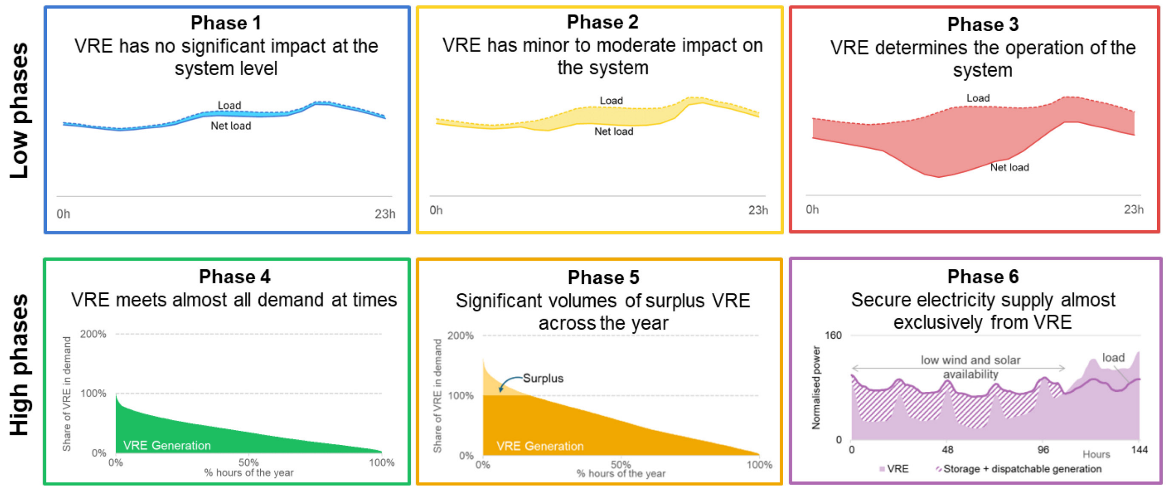
With the rapid deployment of wind and solar, China is transitioning to higher phases of VRE integration by 2030, according to the IEA's framework for VRE integration. Regions with strong renewable potential will face these changes even earlier.

In the early phases of VRE integration (Phases 1 to 3), the impact of VRE on power systems is relatively modest. In these phases, a progressive and targeted approach to policy implementation is often sufficient, without requiring a fundamental overhaul of the power system. Measures introduced in these initial phases lay the groundwork for higher phases later on and include improving forecasting, optimising dispatch processes, increasing flexibility from conventional generators and demand response.

At the national level, China was in Phase 2 in 2022 and is expected to reach Phase 3 in 2030. Success in accommodating the rapid change in generation mix can be achieved through enhancement in grid infrastructure, power market reforms and harnessing flexibility from a wider range of resources, especially from large electricity users. In absence of the necessary integration measures, the system will face increased reliability risks that may hinder the uptake of VRE. Symptoms such as inability to meet peak demand and VRE curtailment may become more frequent.

Beyond 2030, as VRE penetration increases, the Chinese power will transition towards higher phases (Phases 4 and above) and the impact of VRE will become more significant and widespread, with periods of surplus VRE generation becoming more common. Successfully integrating these higher levels of VRE will then require a paradigm shift in how power systems are planned, operated and financed.

The six phases of variable renewable energy integration



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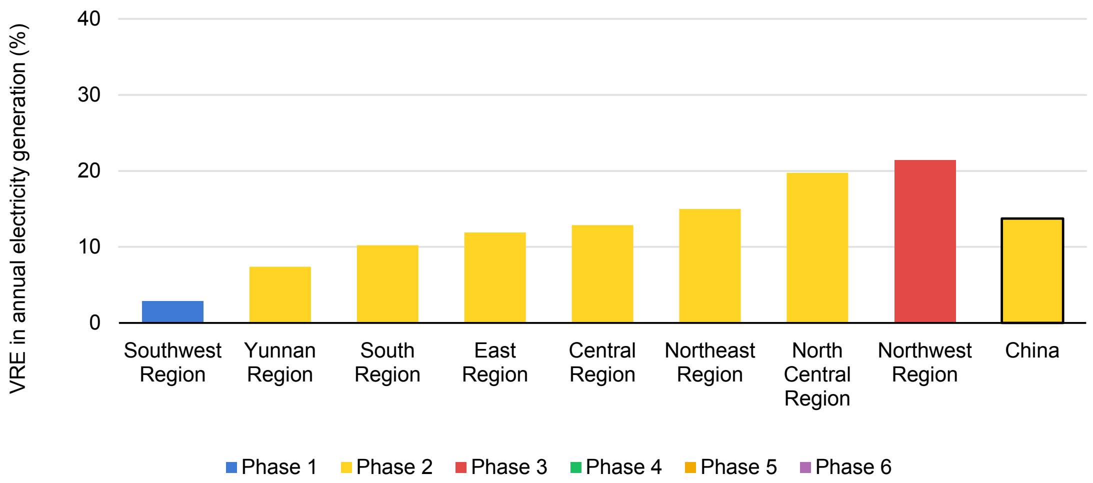
Flexibility needs across the regional diversity of China

China's vast geography presents challenges in connecting high VRE generation potential with demand centres. The diversity in climate and energy resource endowment across regions adds complexity to energy system planning. Long-distance, high-voltage direct current (HVDC) lines have boosted electricity transfer capacity between production and consumption centres, while policies are increasingly encouraging industrial investment inland close to clean energy resource availability. Success in interconnecting regions with varying climate zones and resources enhances electricity supply security by diversifying available sources.

The disparity in the phases of VRE integration across regions in 2022 highlights the value of interregional transmission capacity as a critical aspect of flexibility for China's diverse regions. However, beyond grid capacity, market arrangements must reflect the spatial and temporal value of electricity to ensure efficient system operation and secure supply, especially in regions already in higher phases of VRE integration. This is the case for the Northwest region (Shaanxi, Gansu, Qinghai, Ningxia and Xinjiang) which almost reached Phase 4 in 2022, with power systems there characterised by high VRE penetration and limited local load. Market design must reflect the fact that the regions face diverse issues: the Northwest region clearly faces different challenges than the Southwest region, which remained in phase 1 in 2022, supported by substantial hydro capacity.

Share of VRE and phase of VRE integration at the regional and national levels in China, 2022



The quantitative assessment that follows looks at the national level, but takes into account the transmission barriers between regions.

Assessment of flexibility needs in 2022 and 2030

Our quantitative assessment of China's flexibility needs in 2022 and 2030 highlights the growing demand for flexibility due to the rapid expansion of VRE. The focus of this analysis is on short-term flexibility (hourly to daily), which is becoming increasingly critical as wind and solar power are integrated into the grid. Although equally important in the future, long-term flexibility (seasonal) is expected to be met largely by the sizeable existing and planned fleet of coal and pumped hydropower plants by 2030.

Overview of the model

The assessment of China's flexibility needs is performed with the IEA Regional Power System model for the Announced Pledges Scenario (APS) for 2022 and 2030. This scenario is in line with China's announced pledges and targets for emissions reduction, in particular with the dual carbon goals (peaking carbon dioxide emissions before 2030 and reaching carbon neutrality before 2060). The national-level supply and demand inputs come from the IEA Global Energy and Climate model (GECM) and are disaggregated into eight regions with regional transmission interconnection between them.

The Annex provides details of the modelling methodology.

Flexibility across timescales

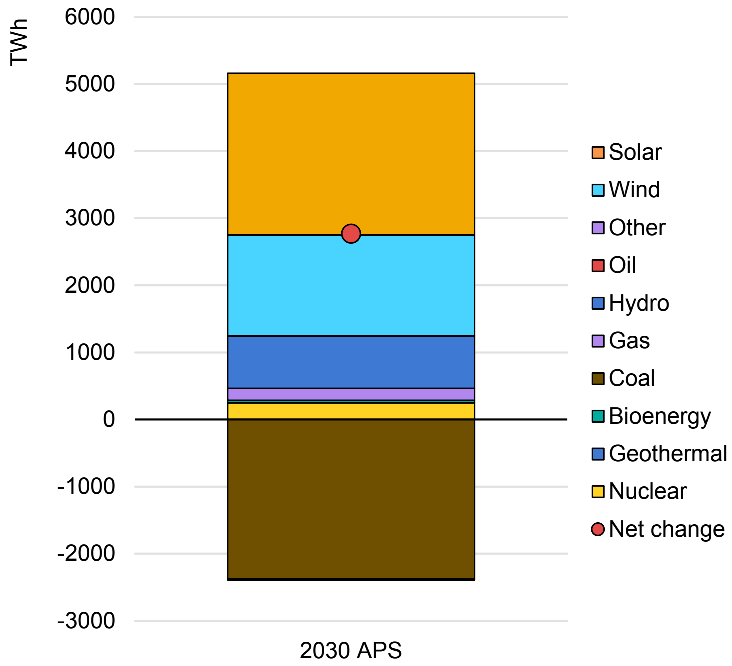
Flexibility needs are spread across multiple timescales. Short-term flexibility is required primarily to accommodate daily fluctuations in demand and VRE output. In this report, short-term flexibility is calculated as the average hourly ramp of the net load (or residual load, which is the remaining total load after subtracting wind and solar generation) during the 100 hours with the highest upward ramps, divided by the average hourly electricity demand for the year (which does not include pumped storage pumping, electricity consumption from electrolysers or net exports). Especially in areas with high penetration of solar PV, steeper ramps and more frequent periods of negative net load require rapid adjustments in supply to maintain grid stability. These fluctuations will continue to increase as solar and wind capacities grow.

Long-term flexibility is currently supported by China's robust fleet of coal plants, which can handle seasonal variations in demand and VRE supply. The existing dispatchable hydro capacity also provides a significant buffer for long-duration flexibility. At the local scale however, some provinces or regions might need to consider long-duration flexibility earlier than others, due to their relative geographical isolation (Inner Mongolia, Hainan).

Drivers of flexibility needs to 2030

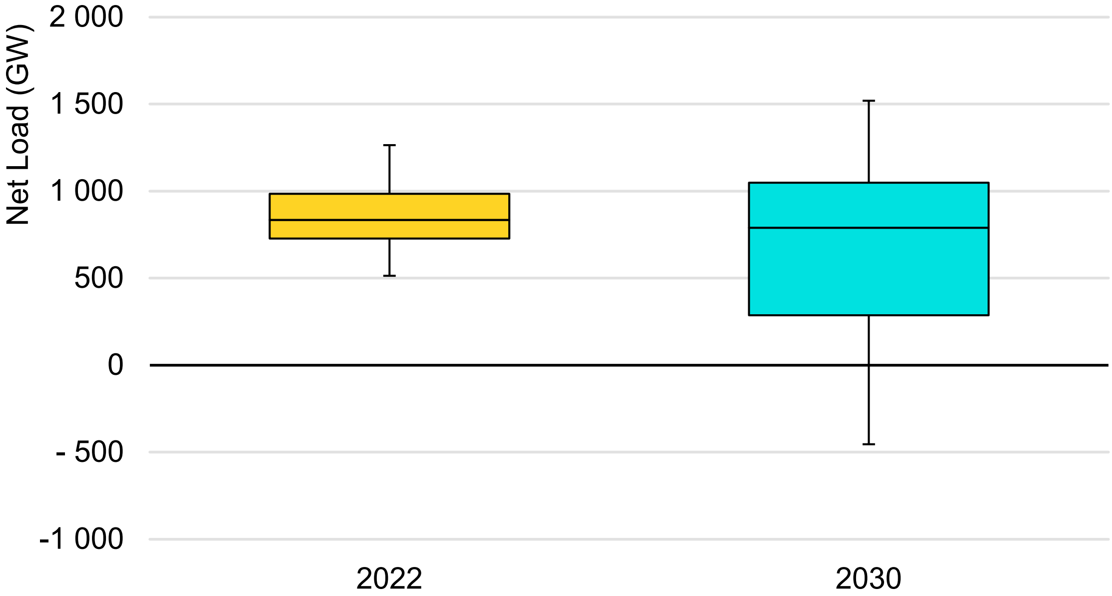
Between 2022 and 2030, VRE generation is expected to grow more quickly than demand. In the APS in 2030, wind and solar power is forecast to meet 150% of the additional load compared to 2022, displacing thermal (mostly coal) generation sources. To successfully capitalise on these resources, integrating them into the power system is a priority, and various means to enhance system flexibility are needed to manage their variability and keep curtailment under control.

Increase in generation by technology in the Announced Pledges Scenario from 2022 to 2030



China was in Phase 2 in 2022 but will reach Phase 3 of VRE integration at the national level by 2030. VRE generation exceeds demand for 15% of the year in the 2030 APS (before curtailment is enacted), while the distribution of net load values is significantly wider in 2030, revealing a need for greater flexibility. As mentioned earlier, individual provinces, particularly in the Northwest Region, are already experiencing integration challenges typical of Phase 3 or above due to concentration of renewable resources and geographical distribution of load centres. In some places, flexibility gaps are evident, including difficulties in meeting peak demand, insufficient load during off-peak periods, rising curtailment rates and conflicts between electricity and heat demand during the heating season.

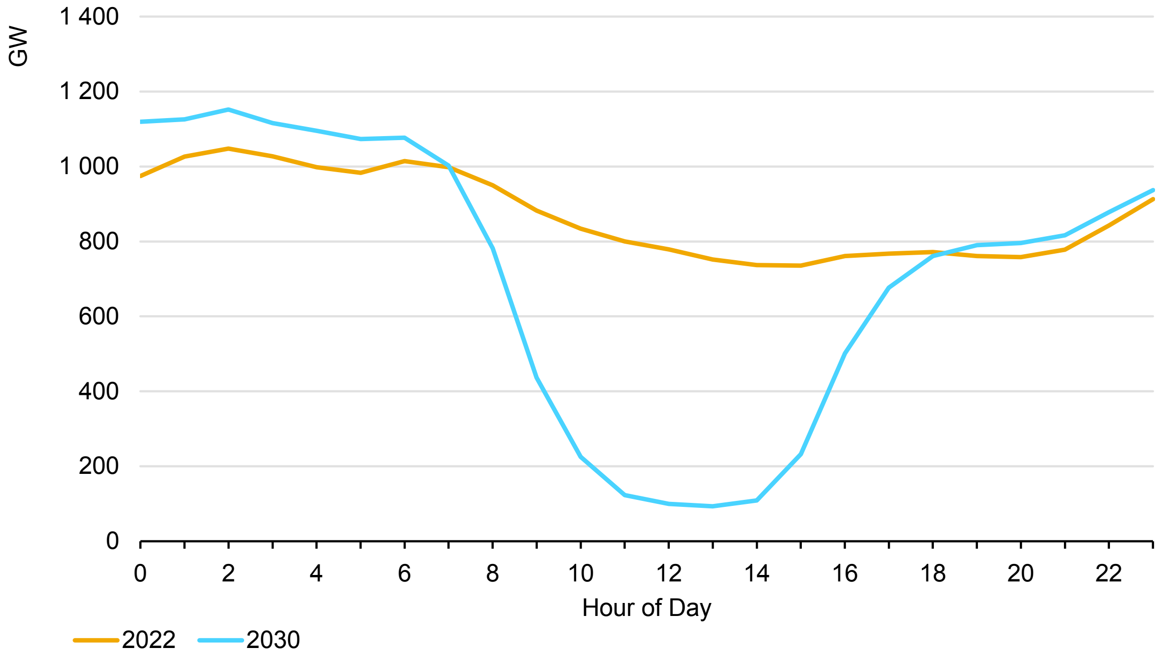
Distribution of hourly net load values at the national level in China before curtailment in the Announced Pledges Scenario, 2022 and 2030

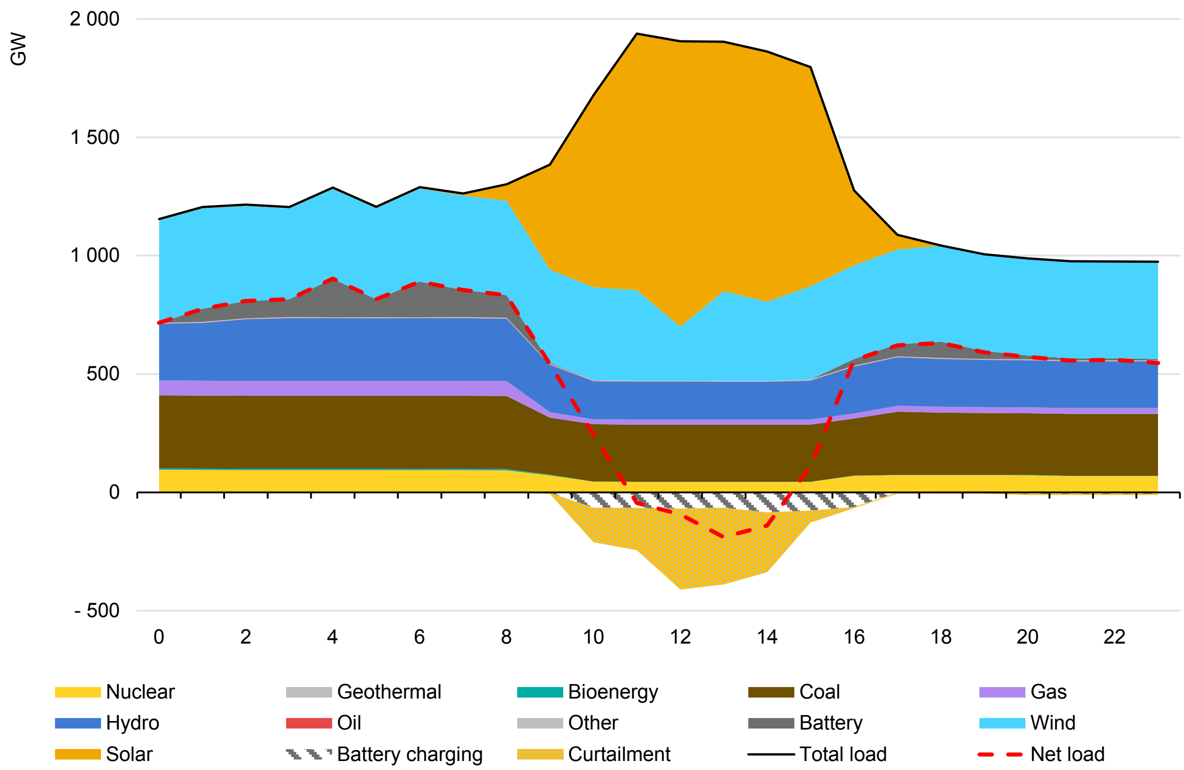


Notes: Net load is total load minus variable renewables (wind and solar PV) generation. Net load is negative when available VRE generation exceeds demand, before curtailment action is taken. The horizontal line inside each box represents the median value, the high and low horizontal edges of each box represent the 75th and 25th quantiles, respectively, and the whiskers represent the 2nd and 98th quantiles of the data.

Changes in renewable generation availability can result in steeper supply ramps. While demand growth may increase flexibility requirements, high solar PV penetration necessitates more flexibility from the rest of the power system to adapt to its generating profile. Net load decreased in the morning hours in 2022 as solar PV generation increases, a trend set to increase significantly in 2030, accompanied by a substantial upward ramp in the late afternoon to compensate for solar decreasing towards sunset.

Comparison of median daily net load profiles in the Announced Pledges Scenario between 2022 and 2030 (top) and generation stack on day with highest total load in 2030 (bottom)

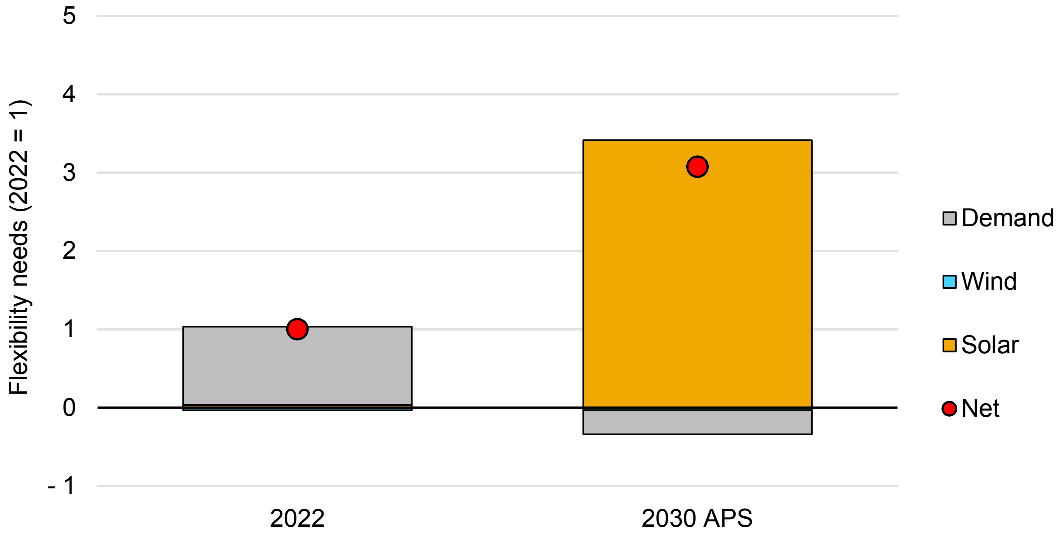




Notes: Median daily net load profiles (top) show the net load by hour, after curtailment action has been taken. The generation stack (bottom) shows the aggregated nation-level generation and the net load.

Beyond ramping to compensate for changes in VRE availability, thermal plants may fundamentally change their operating schedules by increasingly choosing to shut down during the middle of the day, rather than running through to the evening. This could increase the number of plant starts at the beginning of ramping periods, requiring sufficient non-thermal flexibility to cover periodic unplanned outages.

Short-term flexibility needs in China in 2030 as a proportion of 2022



Notes: Flexibility needs for 2030 are calculated based on hourly changes in net load (total load less wind and solar PV generation) for the 100 hours with highest (positive) net load ramps, scaled as a proportion of the average hourly load. A negative driving factor represents a contribution that reduces the impact of the main drivers of flexibility needs. In this case, this occurs because the variability of demand is downward when the net load variability is upward, and vice versa.

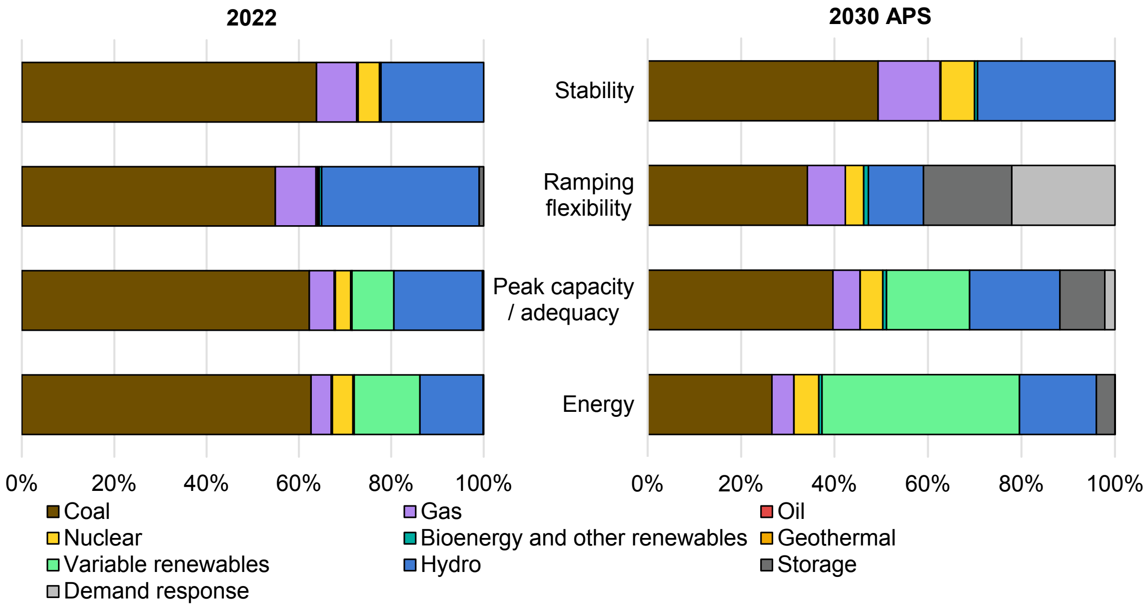
As the share of solar PV and wind increases, short-term flexibility requirements will rise dramatically, tripling between 2022 and 2030. Short-term flexibility will be essential to accommodate the growing disparity between high midday VRE generation and evening demand peaks. The need for short-term ramping capability is driven by solar power, which generates the bulk of its output during the day. Supply-side flexibility such as storage can shift the dispatch of some solar generation to other times of the day, while demand-side flexibility can shift some demand towards this solar peak to reduce curtailment.

Flexibility resources in China towards 2030

China's flexibility resources have traditionally been concentrated on the supply side, with a strong reliance on thermal plants and hydropower. However, as the power system transitions to higher VRE integration, technologies such as battery and pumped hydro storage, demand response and virtual power plants (VPP), and water electrolysers are bound to play a growing role in meeting flexibility needs. This section examines the key sources of flexibility in China and the main policies supporting their development.

Our analysis shows that 58% of flexibility needs in China in 2030 can be fulfilled with non-fossil resources. Building a flexibility portfolio aligned with China's decarbonisation objectives will require scaling up new low-carbon flexibility resources and developing the enabling infrastructure, such as grids, and digital devices. It also involves lifting existing barriers hindering the maximisation of China's power system flexibility, described at the end of this section.

Contribution to the main system services in China, in 2022 (left) and in the 2030 Announced Pledges Scenario (right)



Notes: Stability summarises the contribution to system inertia in the 100 lowest-inertia hours, though inertia is only one aspect of system stability and detailed technical studies are required to capture all components. Ramping flexibility summarises the contribution to the top 100 positive hourly net-load ramps. Peak capacity/adequacy summarises the contribution to the 100 highest-net-load hours. Demand response is active in industrial, transport, commercial, residential and agricultural demand in the 2030 APS. Energy shows the proportion of the total annual generation requirement delivered by the respective technology.

Characteristics of main flexibility sources

Type			Operation range (rated capacity)	Ramping rate (rated capacity/min)	Start-up time	Storage duration	Weather-dependent	Round-trip efficiency	Timeframe of management			Current economics
									Short-term	Medium-term	Long-term	
Supply side	Coal-fired unit	Normal	50-100%	1-2%	6-10h	-	x	48%				$$$
		Retrofitted	30-100%	3-6%	4-5h							$$
	Coal-fired cogeneration plant	Normal	80-100%	1-2%	6-10h	-	x	48%				$$$
		Retrofitted	50-100%	3-6%	4-5h							$$
	Gas plant		20-100%	8-15%	15 min-2h	-	x	60%				$$$
	Dispatchable hydropower		0-100%	20%	<1h	-	✓	90%				$$$$
	Nuclear power plant		30-100%	2.5-5%	24-48h	-	x	35%				$$$$
	Concentrated solar power		20-100%	20%	<1h	Hours	✓	15-21%				$$$$
Storage	Pumped hydro storage		-/+100 %	10-50%	<0.1h	Hours to days	✓	65-85%				$$$
	Electrochemical storage		-/+100 %	100%	<0.1h	Hours	x	90%			-	$$
	Green hydrogen (Power to H2)		0-160% depending on electrolyser technology	0.2-20%/s depending on electrolyser technology	<1h	Hours to months	x	35-50%				$$$$
Demand-side	Demand response	Industrial process	3-5% of peak load required and up to 10% in some regions	Instantaneous	<0.1h	-	x	99%				$$
		AC/ heating				-	✓	95%				$
		EV-grid interaction				Hours	x	90%				$

Notes: "Short-term" timeframe of management refers to second- or minute-level response capability, "medium-term" refers to hourly or daily regulation, and "long-term" refers to regulation across weeks, months or seasons. The darker shade of green means that the flexibility source is more adapted to this timeframe of management.

"Current economics" considers the unit cost (RMB/kW) of technologies at the current level. For load-side technologies, only the investment cost of the equipment required to provide flexibility is accounted for. The technical characteristics of each technology reflect global averages, except for coal power, which uses China-specific data.

Sources: Yuan Jiahai, Zhang Jian (2022) Improving Power System Flexibility: Technical Pathways, Economic Analysis, and Policy Recommendations; Michael Lechl et al. (2023), A review of models for energy system flexibility requirements and potentials using the new FLEXBLOX taxonomy; Zhang Liyue, Xu Qingyu, Liu Yujing, et al. (2024), Build a high-quality new power system and accelerate the development of low- and zero-carbon flexible resources; Deloitte (2021), Fueling the future of mobility: hydrogen electrolyzers.

Thermal power plants: the current backbone of flexibility

Coal plants remain central to China's flexibility strategy, given China's abundant coal resources and China's energy security strategy that reaffirms coal as the "ballast stone" of its power system. In 2023, coal accounted for nearly 60% of electricity generation and 40% of installed capacity. However, its role is expected to shift in the long term, moving from being a core energy provider to focusing primarily on supporting system flexibility and ensuring adequacy. While coal power performs well for medium- and long-term flexibility, it is not the most adequate resource for the very fast regulation and ramping services which are needed in a system with high shares of VRE.

In contrast, gas peaking plants represent a very low share of the total thermal fleet, due to their significantly higher marginal cost and the dependence of China on gas imports. Safety concerns and high operational costs still limit the role of nuclear in short-term flexibility provision.

Coal plant retrofits are taking place in parallel with the construction of new flexible power plants

The Five-Year Plans since 2016 have emphasised retrofitting coal-fired plants to enhance flexibility. Such retrofits can be carried out in a few months and are aimed at lowering the minimum operating range, increasing the ramping capability, and reducing the start-up time to allow for frequent up and down cycling. The main challenges encountered when activating this flexibility are often related to operational practices and contract structures. Flexibility demands more frequent adjustments in plant output, requiring more active onsite roles. In addition, contracts based on annual total output tend to favour steady production to minimise equipment wear, rather than encouraging flexibility. Such flexible operation also comes at the cost of increased emissions per kWh, challenging the notable progress China has made in reducing the carbon intensity of coal power in recent years.

Since 2021, 300 GW of coal capacity has been retrofitted, surpassing the 14th Five-Year Plan's target of 200 GW. In February 2024, the Chinese authorities mandated that all retrofittable coal units (estimated between 500 and 700 GW) undergo flexibility modifications by 2027. This policy has accelerated retrofits, particularly in VRE-heavy regions. In regions with a high proportion of renewable energy, coal plants should be able to reduce their minimum output to less than 30% of rated capacity. In addition, the exploration of market-based revenues for the flexible operation of coal plants is promoted.

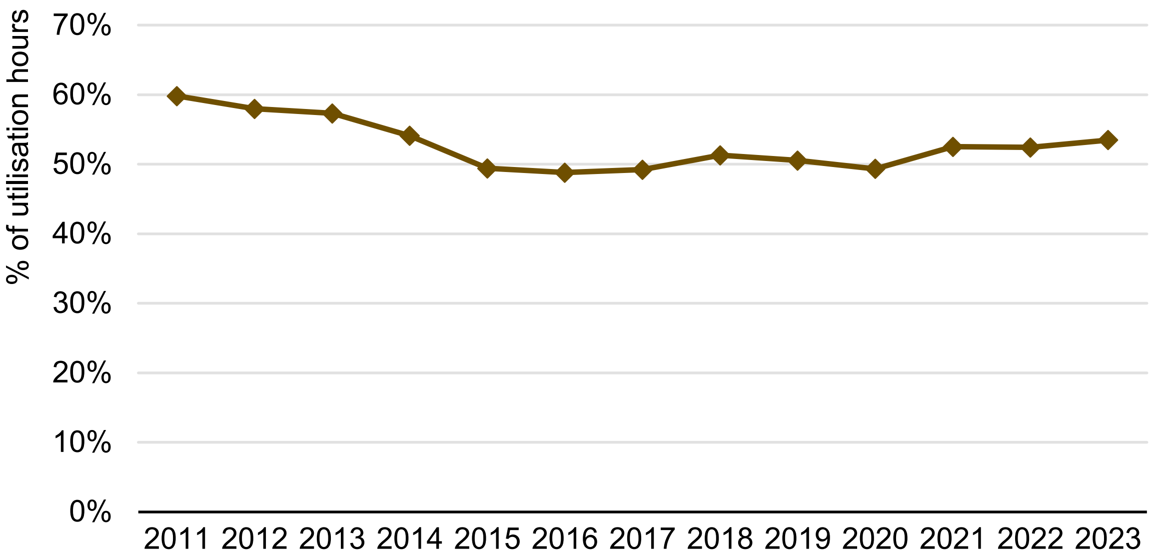
Coal-fired plant retrofits targets and achievements

	13th Five-Year Plan (2016-2020)	14th Five-Year Plan (2021-2025)
Target	220 GW	200 GW
Actual retrofits	162 GW (2020)	300 GW (2023)
Total coal power fleet	1083 GW (2020)	1165 GW (2023)

Sources: IEA based on data from National Development and Reform Commission (NDRC), National Energy Administration (NEA), China Electric Power Planning and Engineering Institute (EPPEI), China Electricity Council (CEC).

The government has embraced the strategy of progressively transforming its coal power fleet from baseload generators to peaker plants. This approach is viewed as the fastest way to support the rapid development of wind and solar energy and mitigate their variability. With decreasing utilisation hours, coal power plants are operating on average at about half their capacity nationwide. Although a slight increase has been observed in recent years, the average capacity factor of coal is expected to decrease to 30% by 2030 under the APS. This poses a risk to the profitability of plant owners, who used to rely on payments based on electricity production. In this context, the government introduced capacity payments for coal generators in January 2024, designed to help plant owners partially recover their fixed costs.

Average utilisation hours of coal power plants in China, 2011-2023

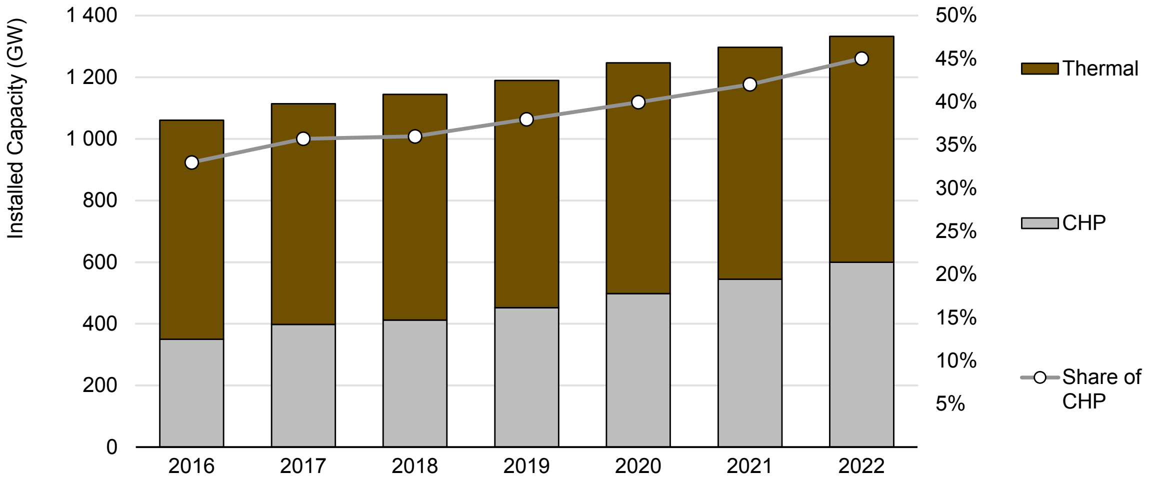


Source: IEA based on data from the National Development and Reform Commission, National Energy Administration and Dianchacha.

Coupled heat and power production is limiting coal flexibility during the heating season

In China, the supply of electricity and heat is highly coupled, with coal combined-heat-and-power (CHP) plants being the primary source for heating, supplying about 48% of the heat demand in northern areas. CHP plants represent 45% of the thermal power plant capacity, but they are by nature less flexible than pure condensing plants (if not coupled with thermal storage), since their electricity production is linked with heat demand in the northern areas. For instance, the minimum output of retrofitted coal-fired condensing units can be as low as 20% of their rated power, while for retrofitted CHP units it can be only 50%.

Installed capacity of thermal and CHP units in China, 2016-2022



Source: IEA based on Dianchacha and China Electricity Council data compiled by Huaon Research Institute.

Decoupling electricity and heat are being explored through low-pressure cylinder shedding, electric boilers and molten-salt storage. Water storage is a simple way to short-term decoupling, but other technologies also drive significant interest in China, despite being associated with high costs and comparatively low compensation combined with operational complexities, which make them difficult to scale quickly.

In addition, the deployment of large-scale heat pumps into existing district heating systems constitutes a solution to reduce the reliance on CHP plants and further decarbonise heat. When integrated with thermal energy storage, heat pumps can help minimise VRE curtailment, enhancing system efficiency and flexibility.

Heat-power decoupling technologies

Technology	Cost	Advantages	Disadvantages
Low-pressure cylinder shedding	Low	Easy switch-ability of operational modes, deeper operational range	Lack of data on its impact on units, limited flexibility improvement
Bypass steam heating	Low	Mature technology, high level of heat-power decoupling	Poor heating efficiency and high requirements for units' operational reliability
Electric boiler	High	Minimal retrofit work, mature technology, high level of heat-power decoupling, high flexibility	High investment costs, poor economic efficiency
Water storage	Normal	Mature technology, minimal retrofit work	High space requirement, not suitable for prolonged periods of low demand of electricity
Molten-salt storage	High	High flexibility, deeper operational range, long duration, high safety, long life	High technical complexity, high space requirement, high investment costs

Source: Peking University Institute of Energy and Shandong Heat Energy And Electric Power Design Institute (2024), Study on Optimizing the 300 MW Coal-Fired Power Fleet in Shandong, Focusing On Flexible Peak Shaving and Stable Heating Supply.

Flexibility from nuclear power plants

China currently has 56 operational nuclear reactors, and while their capacity for flexibility remains underutilised, their potential for peak regulation is being piloted. The output of the French nuclear fleet, as an example, can vary significantly in response to changes in the net load, with reactors able to ramp up or down between 20% and 100% of their nominal capacity within 30 minutes twice a day.

While China's nuclear fleet operates primarily as baseload power (and in some cases, for district heating), research into flexible nuclear operations has gained momentum. The Guidance for Strengthening Energy Storage for Peak-Shaving and Smart Dispatch Capability published by the NDRC in February 2024 encourages peak shaving and the use of nuclear plants in frequency regulation services. However, safety concerns and high operational costs still limit their role in short-term flexibility provision.

Hydropower: essential for grid stability

Hydropower is one of China's essential flexibility resources, capable of balancing daily and seasonal fluctuations in VRE output. Reservoir-based hydropower plants can store excess energy and release it during peak demand periods, providing both baseload generation and ancillary services such as frequency regulation.

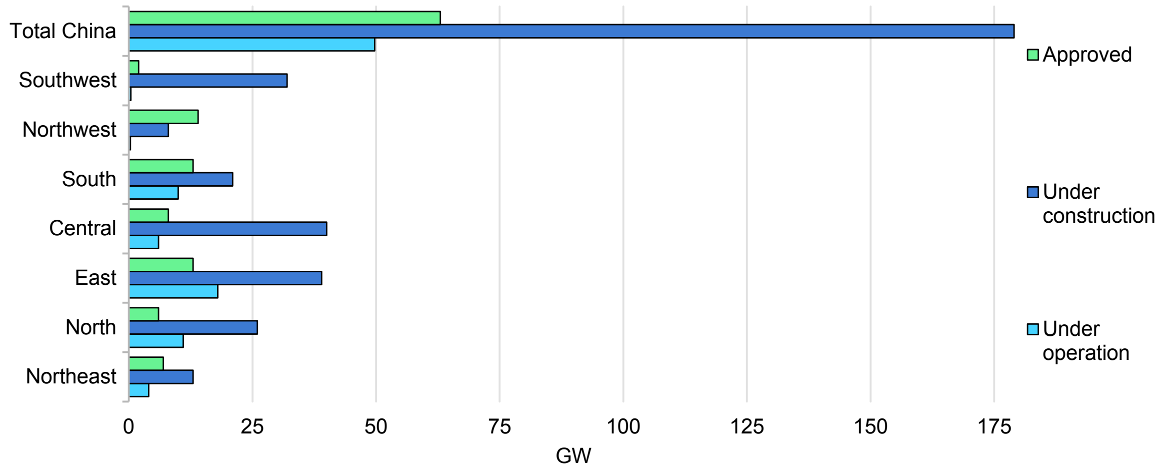
Longyangxia power plant in Qinghai province is a prime example of a facility with a large upstream reservoir, capable of providing seasonal and yearly regulation. However, the fleet of such projects is currently limited in China. When equipped with (bidirectional) pumped storage, hydropower plants can operate in an even more flexible way. The 14th Five-Year Plan targets an increase in hydropower capacity to 442 GW by 2025, up from 370 GW in 2020, which includes both conventional and pumped storage projects. Yet, recurrent droughts have been depleting hydropower production, as evidenced by consecutive declines in 2022 and 2023.

Pumped hydro has been the leading storage resource and is set to increase

China has the largest pumped hydro storage (PHS) capacity worldwide, with 51 GW installed as of 2023. The government has set an ambitious goal of reaching 80 GW of PHS by 2027 and 120 GW by 2030, with 49 new projects (63 GW) approved in 2023 alone.

PHS plays a crucial role not only in managing daily fluctuations, providing short-term balancing services and inertia, but also in managing variability over extended periods of time. Since 2023, operating and planned pumped hydro power stations across the country have been entitled to a capacity tariff on top of the electricity tariff, which is conducive to driving more investments in this technology. However, the development of new PHS projects faces challenges, including long lead times (up to six years) and geographical limitations.

Pumped hydro storage (PHS) capacity in 2023 and pipeline projects by region



Note: Approved capacity covers only projects which received permission in 2023 from the Chinese government to start construction.
Source: IEA based on data from China Renewable Energy Engineering Institute and China Pumped Storage Association.

End use electrification: enhancing flexibility opportunities

The demand side represents a large, mostly untapped source of flexibility. By 2030, our analysis shows that demand response could provide up to 22% of short-term flexibility needs in China. Electrification of end uses is only reinforcing this potential: the share of electricity in final consumption reached about 28% in 2023 and is expected to continuously increase by 2030 driven by the road transport, industry and building sectors.

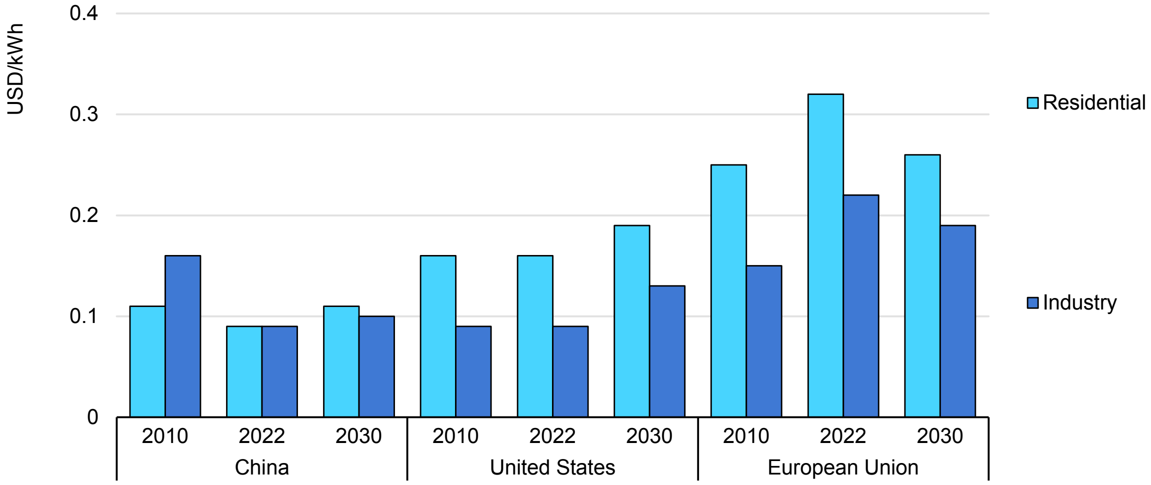
Managing summer and winter peak loads has been the main driver for developing demand response in China in recent years. Most demand-side management efforts have relied on administrative measures, such as issuing orderly power consumption notices to large consumers during tight supply periods. For example, during the summer 2022 power crunch in Sichuan, the provincial government issued an emergency notice ordering businesses to reduce or halt power use to prioritise households. Similar measures were taken during the 2021 energy crisis, when surging coal prices caused a nationwide power shortage. Such administrative measures can undermine firms' anticipatory investments.

However, some provinces are now exploring demand-side response as a long-term solution for maintaining adequacy, introducing market-based mechanisms and developing virtual power plants (VPPs) to aggregate the load and storage of various users.

The "Electricity Demand Side Management Measures" released in 2023 set a goal for provinces to reach demand response capability of 3% to 5% of their maximum electricity load by 2025. For specific regions experiencing issues with peak load management or VRE consumption, an action plan by 2027 set this target to 10% of the peak load. By 2030, the aim is to establish a large-scale, real-time demand response capability. The policy also emphasises the prioritisation of market-based demand response over regulated measures.

Given their share in total electricity consumption, demand-response potential is largest in the industry sector and for other large commercial users. It is also often more cost-effective to install the necessary equipment at these sites. Since 2021, commercial and industrial users are required to buy electricity on power markets. However, in practice, fixed-price packages on retail markets still make it hard to solicit real-time demand response from them according to system conditions. Home energy management systems and electric vehicles uptake are unlocking the possibility of residential demand as well. Yet there is little awareness among households nor incentives to engage in such programmes mainly because they face very low and usually fixed electricity prices, unlike in countries where residential demand-side response is more active.

Residential and industrial electricity prices in China, the United States and the European Union in the Announced Pledges Scenario, 2010-2030



Source: IEA (2024), Strategies for Affordable and Fair Clean Energy Transitions.

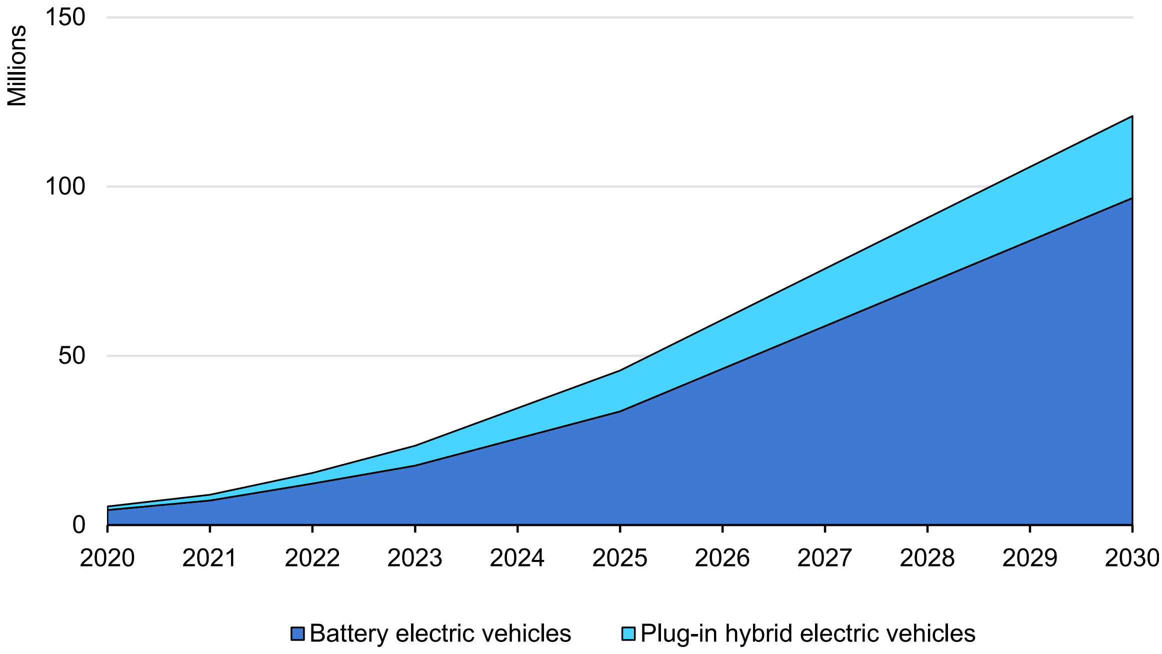
Managed EV charging offers a yet-to-be flexibility resource in a context of booming EV deployment

China is experiencing a deployment of new energy vehicles (NEVs)[1] exceeding all expectations. In 2023, 23.4 million NEVs were on the road in the country, led by electric cars which represented more than one in three new car registrations. Charging piles numbers increased by 65% year on year, raising the total number of charging points to 8.6 million in 2023. For the first time in July 2024, NEVs represented the majority of new car sales, overtaking conventional gasoline cars, and exceeding by far the announcement, just a few months before, of a 45% NEV sales share target for 2027.

This fast deployment is already causing large spikes in electricity demand, potentially straining the grid when charging occurs at peak times or creating new peaks. In Zhejiang and Guangdong provinces for example, electric vehicle (EV) charging represents can exceed 2% of the evening peak demand.

[1] In the Chinese terminology, NEVs include battery, plug-in hybrid and hydrogen fuel cell electric vehicles.

Electric vehicles stock in China under the Announced Pledges Scenario, 2020-2030



Notes: Electric vehicles include cars, trucks, buses and vans. Fuel cell electric vehicles are not included here as they cannot be used for managed EV charging. Data after 2023 are projected according to the APS.
Source: IEA (2024), Global EV Outlook.

With their onboard battery packs, battery and plug-in hybrid EVs can transform from a burden to a valuable grid flexibility resource by scheduling recharging at periods when it is the most beneficial. The first and easiest way to do this is through unidirectional smart charging (or V1G), which means carrying out the charging of EVs at times when it minimises the impact on the system, for example at night, or when the VRE production is abundant in the afternoon. Hourly or sub-hourly price signals can guide consumers to adopt grid-friendly charging habits, such as time-of-use (TOU) tariffs which are applied in several public and residential charging stations in China. This strategy constitutes the bulk of the flexibility potential associated with EVs and has proven successful in several provinces. For example, managed EV charging, supported by TOU tariffs, TOU service fees and charging coupons, reduced peak load by 12 MW (equivalent to the demand of about 6 000 households at peak hours) and achieved a total energy shifting of 17 MWh (the daily consumption of about 2 000 households) in Jiangsu province in August 2024.

The second way is through vehicle-to-grid (V2G or bidirectional charging), in which EV batteries can be used in a flexible way, recharging during off-peak periods, and re-injecting power into the grid when needed, with financial compensation for the user. V2G can be used as a last resort reserve and does not need to be activated frequently. Several demonstration projects are ongoing in localities looking to develop their demand-response capacity and where the fleet of EVs is already significant, such as in Jiangsu, Zhejiang and Guangdong. Most are operated by grid companies.

Major vehicle-to-grid (V2G) demonstration projects in China

Area	Projects
Jiangsu	China's largest V2G, located in Wuxi, comprising 59 V2G chargers with a maximum discharge power of 2.1 MW and energy shifting of 3.15 MWh
Zhejiang	V2G projects comprising 2 709 V1G stations and 12 V2G stations (94 charging points), enabling a maximum peak reduction of 23.9 MW
Shanghai	Seven V2G projects announced in 2023 by the municipality, of which NIO's first batch of 10 V2G charging stations officially began operation in January 2024
Guangdong	330 000 charging facilities and 137 V2G demonstration stations are operating in Shenzhen, with over 400 MW of regulation capacity
Beijing	First VG2 station in commercial operation in Beijing, with 26 V2G chargers

The government actively supports harnessing the flexibility potential of EVs as illustrated through the policy released in January 2024 to facilitate the integration of NEVs to the grid. The focus by the end of 2025 is on expanding V2G demonstration pilots, with more than 50 projects in five cities, promoting battery-swapping projects and attempting to ensure that 60 to 80% of the charging of EVs in public and private charging piles, respectively, occurs at off-peak periods. By 2030, NEVs are expected to provide 10 GW of flexible capacity through V2G operations.

However, fulfilling this ambition and fully tapping into this flexibility resource requires overcoming several existing barriers. Most EV owners live in urban areas and do not own a private charger. They must use commercial chargers: although TOU clauses apply, users cannot stay connected at all times (which limits opportunities for bidirectional charging). Users recharging their EV at home are either not exposed to variable electricity prices, or the low rates and price differences do not constitute a strong incentive for them to opt into managed charging programmes.

Going further, widespread development of V2G would require bidirectional charging stations which are more expensive to build, up to 2 to 3 times the cost of standard stations. In 2023, less than 0.03% of charging piles were V2G-ready in China. Viable business models are yet to be found, both for station operators and for EV load aggregators, to support the deployment of the technology, while regulatory barriers for households to engage in bidirectional charging remain. Additionally, concerns about the impact of V2G on battery lifespan have been central in the debate around the economic viability of V2G operations.

Manufacturer warranties or alternative solutions such as battery swapping to cover these potential risks will have to be addressed to reassure EV owners.

Virtual power plants are demonstrating their ability to provide flexibility services while a viable business model is still lacking

Virtual power plants (VPPs) aggregate the load and generation of distributed energy resources, such as EVs, air conditioners, storage or rooftop solar panels, without geographical limitation. Equipped with a central control system that exchanges and aggregates information from the different units, VPPs can draw on the various capabilities of connected units to participate in electricity markets and provide grid services in a very similar way to traditional plants.

China's VPP landscape is still in the early stages of development, but growing interest and pilot projects signal potential for future expansion. Most VPPs projects are focused on load side aggregation and participate in demand-response events on an invitation basis from the grid company, although the definition of VPPs is not consistent across regions. Their compensation comes from a government fund, along with revenues from peak valley pricing and interprovincial trading. However, the limited occurrence of those demand-response events is challenging the sustainability of the VPP model and most projects currently rely on government subsidies.

For example, the VPPs projects in Shenzhen,[2] for which the aggregated capacity is expected to reach 1 GW by 2025, can enjoy subsidies up to RMB 15 million (USD 2.1 million) for each individual project. Whether revenues from market transactions will suffice for the projects to generate profits in the longer term is yet uncertain. According to predictions by the Development and Reform Commission of Shenzhen Municipality, the revenue from VPP participation in market transactions in Shenzhen is expected to reach RMB 79 million (USD 11.2 million) in 2025. Of this, 77% will come from day-ahead peak shaving transactions, 22% from frequency regulation services, and the remaining 1% from reserve services.

In recent years, several provinces and regions have started opening their electricity markets to VPPs, enabling them to diversify their sources of revenue. Notably, in June 2024, the first batch of VPPs participated in spot trading in Shandong, with a combined capacity of 300 MW. Despite recent progress, industry stakeholders express concern over high market entry thresholds for VPPs which prevent broader participation, along with a lack of standardised codes and specifications across the country.

[2] Source: Working Plan for Development of VPP in Shenzhen (2022-2025) (Draft) by Shenzhen Development and Reform Commission.

Services deployed in China for VPP participation in selected jurisdictions

Service	Locality	Minimum capacity and/or duration requirements	Price caps
Peak regulation	North Central region (since 2020)	≥ 10 MW/30 MWh	0.6 CNY/kWh
	Shanxi province (since 2020)	≥ 20 MW ≥ 2h /day	0.2 / 0.3 CNY/kWh (Heating/ non-heating season)
Demand response	Shanghai city (since 2014)	-	Peak shaving: CNY 30/ kW Valley filling: CNY 12/ kW
	Jiangsu province (since 2015)	≥ 10 MW ≥ 2 hours	3-4.8 (Peak) 0.6 (Valley)
	Guangdong province (since 2022)	≥ 0.3 MW ≥ 2 hours	3.5 CNY/kWh (day-ahead invitation) 5 CNY/kWh (interruptible)
	Shenzhen city (since 2023)	≥ 1 MW ≥ 30 minutes	3.5 CNY/kWh
Frequency regulation	Zhejiang province (since 2024)	≥ 5 MW ≥ 1 hours	0.12 CNY/kWh (Primary) 0.06 CNY/kWh (Secondary)
	Southern region (since 2020)	≥ 10 MW ≥ 1 hour	5 CNY / MW
Reserve	Zhejiang province (since 2024)	≥ 1 MWh / 1 MW ≥ 1 hour	0.015 CNY/kWh
	Central region (since 2022)	-	-
	Southern region (since 2022)	≥ 10 MW ≥ 1 hour	CNY 50 / MW
Reactive control	Zhejiang province (since 2021)	-	60 CNY / kvar
Energy arbitrage	Guangdong province (since 2022)	≥ 1 MW ≥ 1 hour	-
	Shanxi province (since 2022)	≥ 20 MW ≥ 2 hours	-
	Shandong province (since 2024)	≥ 5 MW ≥ 1 hour	

Interconnection, batteries and curtailment: managing surplus and deficits of VRE production

Inflexible contracts limit the benefits of UHV transmission network

Better sharing of resources across China by using and expanding interconnections would result in significant benefits. China's ultra-high voltage (UHV) transmission network already plays a critical role in balancing regional demand and supply mismatches, facilitating the transfer of renewable electricity from resource-rich areas in the "three north regions" (northeast, north and northwest) to major consumption centres in the east and south. Examples of such projects include the Changji-Guquan (from Xinjiang to Anhui) ±1100 kV UHVDC transmission project which has the highest transmission capacity in China.

The 14th Five-Year Plan (2021-2025) includes 12 new UHV projects (9 HVDC, 3 AC) to connect GW-scale VRE projects in the north and west with demand centres in the east and south. Despite these ambitious plans, VRE capacity is being built at a much faster rate than the physical infrastructure needed for interconnection. Recent development of distributed renewables and offshore wind in coastal provinces may help reduce the need for costly, long-to-develop UHV transmission lines.

On the contractual side, rigid interprovincial contracts currently limit the flexible use of this infrastructure. The majority of interprovincial power transfers occur under mid- to long-term contracts, which reduce the grid's ability to adapt to real-time fluctuations. Most of the cross-provincial trade is done under "grid-to-grid" or "point-to-grid" MLT contracts, meaning that only grid companies can serve as counter parties on the receiving end. This rule also applies for interprovincial spot trading for surplus power, where grid companies are the only importers but cannot sell this electricity on the local spot markets. The firm aspect of those contracts implies that the imported electricity is taken as firm input in the dispatch of the province or region, whatever the local needs of the system are, therefore leaving little space for short-term adjustment in the spot markets. However, the National Energy Administration (NEA) recently opened the door to the non-physical execution of MLT interprovincial contracts, allowing the sending province to fulfil the transmission plan by purchasing surplus electricity from the receiving province during periods of low prices.

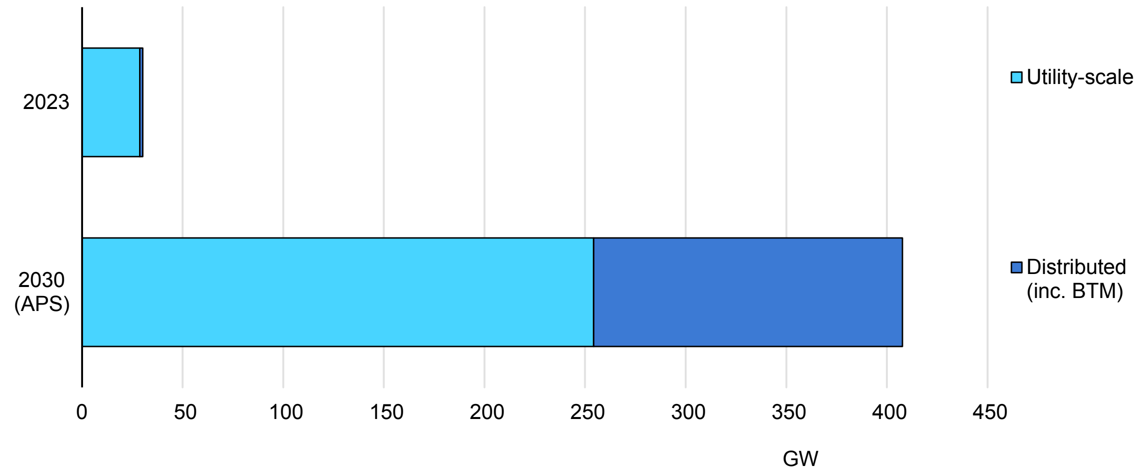
Another aspect preventing the efficient operation of interconnections is the business model for UHV transmission lines projects, which is tied to their utilisation rates. The more electricity they transmit, the more transmission charges grid companies can generate. Given the intermittent nature of wind and solar PV, the lines connecting remote western clean energy bases with consumption centres would be mostly underutilised, which incentivises pairing them with new or existing coal-fired power plants to increase the line's profitability. The 14th Five-Year Plan for renewable energy sets the requirement that new high-voltage lines carry no less than 50% of renewable power, on average, at the national level, with this share reaching already 56.2% in 2022. As some lines are 100% dedicated to exporting hydropower, this target over the national average does not prevent coal power contribution to represent the majority of the power exported from some "clean" energy bases.

Battery storage's fast uptake will be a game changer for short-term flexibility provision

Battery storage is a good candidate to provide (ultra) short-term flexibility and balance variability of VRE output over a few hours. Compared to pumped hydro storage, the lead times to deploy battery storage assets are also much shorter, generally only a few months.

Developing non-hydro storage has been at the core of China's energy strategy in recent years, and the country has become the leading market for battery storage since 2022, outpacing the United States. Lithium-ion batteries represent more than 97% of the 31.4 GW installed capacity of non-hydro storage at the end of 2023. Out of this, 23 GW were added in 2023 alone, with around two-thirds at the utility-scale level. The State Council announced in May 2024 the objective of achieving 40 GW of utility-scale battery storage capacity by the end of 2025, a target that could largely be over-achieved considering the current pace of deployment.

Installed battery storage capacity in 2023 and projected capacity under the Announced Pledges Scenario in 2030



Source: IEA based on data from EPPEI (2023) and IEA (projections).

On the utility-scale side, this rapid uptake is driven mainly by province-level mandates requiring the pairing of solar PV or wind projects with a minimum of 5% to 30% storage capacity depending on the local regulation. The use of energy storage in grid ancillary services, such as frequency regulation and peak shaving, is growing, though utilisation rates remain low for supply-side batteries (6% in 2022) due to underdeveloped market incentives and dispatch practices. As a result, developers have favoured cheap and low-quality technologies that do not meet flexibility requirements.

On the behind-the meter-side, large installations by commercial and industrial consumers are seeking to benefit from TOU pricing, closer to utility-scale systems in terms of size and cost. Some provinces are actively encouraging commercial and industrial consumers to pair rooftop solar PV with storage assets.

Shandong province is leading the way in terms of improving the business case for new energy storage to deliver flexibility. It was the first province to implement the 2022 national policy allowing new energy storage assets to participate in power markets transactions as independent entities. For assets bidding in the spot markets, grid tariffs and taxes are waived during charging to avoid double taxing. Moreover, capacity payments for storage assets are also in place. For smaller assets not directly participating in markets, dynamic TOU tariff adjustments that are more reflective of system needs are conducive of storage investments.

Green hydrogen as a source of seasonal storage in the longer term

Green hydrogen constitutes a decarbonised resource of seasonal flexibility, enabling long-duration energy storage. Surplus renewable electricity is used to power a water electrolyser, and the resulting hydrogen is stored and used at times of need for the system, by a combustion engine or a fuel cell. China's installed capacity of electrolysers surpassed 1 GW in 2023, with ongoing projects expected to expand the fleet to 5 GW by 2025. The 2035 roadmap for hydrogen industrial development released in 2022 also sets objectives to increase production and consumption of green hydrogen in the mid-to-long term.

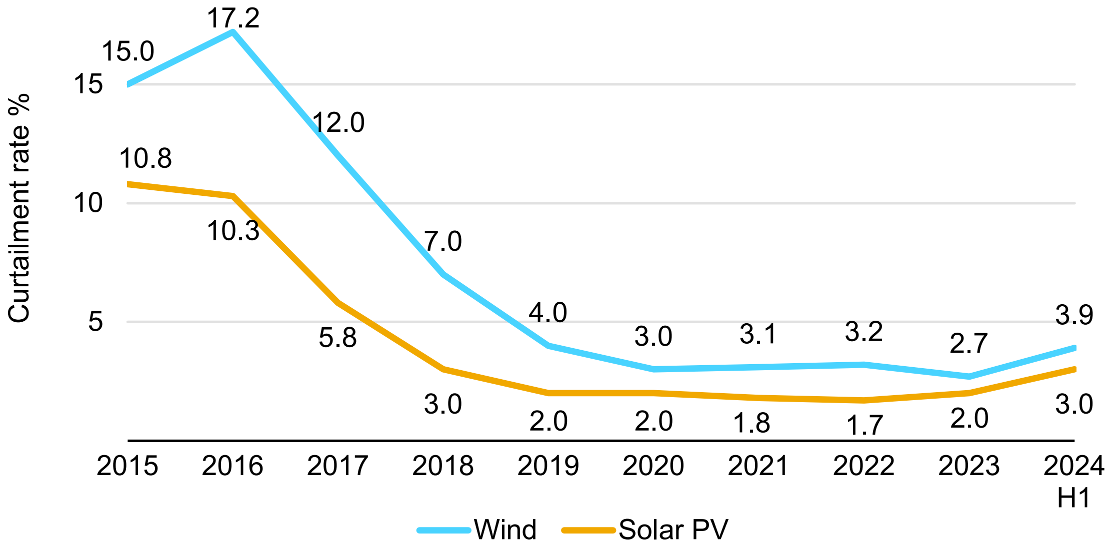
However, green hydrogen is still not competitive with hydrogen produced from coal. The China Hydrogen Alliance reports that in 2022, the lowest costs of green hydrogen were achieved in regions with abundant wind and solar PV resources, such as Ordos in Inner Mongolia and eastern Ningxia, with an average cost of CNY 20/kg. While this is competitive with hydrogen produced from natural gas reforming, which has a national average cost of CNY 25/kg, it remains more expensive than hydrogen produced from coal, which averages CNY 13/kg nationally.

Although demonstration projects are multiplying, such as the Dachen Islands hydrogen pilot in Taizhou, the use of green hydrogen to enhance power system flexibility has not been proven at scale yet and will play only a marginal role by 2030. In addition to the high costs, coupled with low energy conversion efficiency, other constraints relate to the lack of hydrogen infrastructure such as pipeline networks, liquefaction facilities and refuelling stations, and safety concerns. In the longer term and for systems reaching very high shares of VRE, electrolysers could become an important flexibility resource.

Curtailment redline release suggests more widespread use of curtailment in grid operation

In systems with high or very high levels of VRE penetration, particularly under conditions of structural oversupply such as midday solar PV peaks, keeping curtailment close to zero as a policy decision can compromise the cost-effectiveness of running the system. However, apart from this case, for most systems, high levels of technical curtailment[3] are indicative of a lack of flexibility or inadequate grid infrastructure. Curtailing large volumes of VRE production represents a waste of cheap and clean energy and can therefore lead to higher system costs. Moreover, it can undermine VRE plant developers' confidence as they would see a risk in fulfilling their contractual obligations.

Wind and solar PV national curtailment rates in China, 2015-2024



Source: IEA based on data from the National New Energy Consumption Monitoring and Warning Centre.

[3] Here we refer to technical curtailment, implemented by system operators for technical reasons (for example, grid congestion, voltage control issues) as opposed to economic curtailment, which is applied by generators when generation is reduced due to price signals.

Although curtailment levels have significantly decreased since 2016, recent data show that curtailment is rising again. In February 2024, curtailment rates reached their highest levels since monthly reporting began in 2021, with 6.3% for wind and 6.6% for solar, primarily due to grid congestion and a lack of flexible resources. Some provinces and regions facing serious grid congestion issues saw even higher levels, such as Hebei where monthly curtailment rates reached 16% for wind and 12.6% for solar PV.

The government's curtailment cap of 5%, introduced in 2018, has been difficult to maintain due to delays in grid infrastructure development and the rapid growth of VRE capacity. In May 2024, the NEA raised the provincial curtailment cap to 10% in some regions, signalling a more flexible approach to grid congestion management.

To tackle curtailment, Inner Mongolia, Xinjiang and Gansu have recently published policies limiting new VRE projects to "integrated projects" matching wind and solar PV plants with new data centres, hydrogen electrolysers or low-carbon industrial parks.

International experience in dealing with technical curtailment

High levels of technical VRE curtailment can lead to higher power system costs and financial hurdles for wind and solar project developers. At the same time, curtailment can increase the perceived risk of developing new projects, thereby undermining future investments. Technical constraints leading to curtailment can be driven by factors such as delayed grid development, contractual inflexibilities of traditional generators and lack of supply flexibility.

Unlike China, most countries do not set mandatory curtailment limits or a utilisation rate for VRE projects. However, system operators strive to reduce curtailment by taking operational measures, to minimise system costs. For example, the Spanish transmission system operator, Red Eléctrica, introduced in 2022 the Automatic Power Reduction System (SRAP). This voluntary scheme is designed to solve congestion constraints in a corrective instead of preventive manner, that is, by disconnecting participating power plants from the grid to solve grid congestion if it materialises, instead of preventively redispatching power plants based on expected congestion that may not actually happen. As of October 2023, this has allowed the reduction of system costs by avoiding the curtailment of more than 2 TWh that would have occurred if a preventive redispatch approach had been used.

Introducing alternative revenue streams or compensation schemes for managing VRE curtailment can be used as a transitional measure to address underlying systemic causes such as a lack of grid or flexibility development. In Germany, which experiences a lot of grid congestion, the Energy Act was amended in November 2023 to introduce the Use Instead of Curtail mechanism. This scheme incentivises consumers near VRE plants to use excess VRE supply by offering a fixed discount on wholesale electricity prices and an incentive in the form of no network charges or taxes. At the same time, this scheme ensures overall economic efficiency by capping the compensation at how much the alternative redispatching solutions would cost.

Additionally, non-firm connection contracts can increase how much VRE capacity the system can host and at the same time mitigate the impacts of curtailment by offering benefits to developers. For example, from April 2025 system operators in the Netherlands will be allowed to offer contracts to large electricity consumers where these end users will benefit from lower tariffs on the condition of not being able to use the grid at all during certain times of system stress.

Enabling VRE plant owners to access additional revenue streams beyond the energy market, such as through ancillary services or capacity markets, helps to support their investments by remunerating the value they provide to the system beyond energy generation, thus mitigating the financial impacts of curtailment.

Barriers to flexibility in China

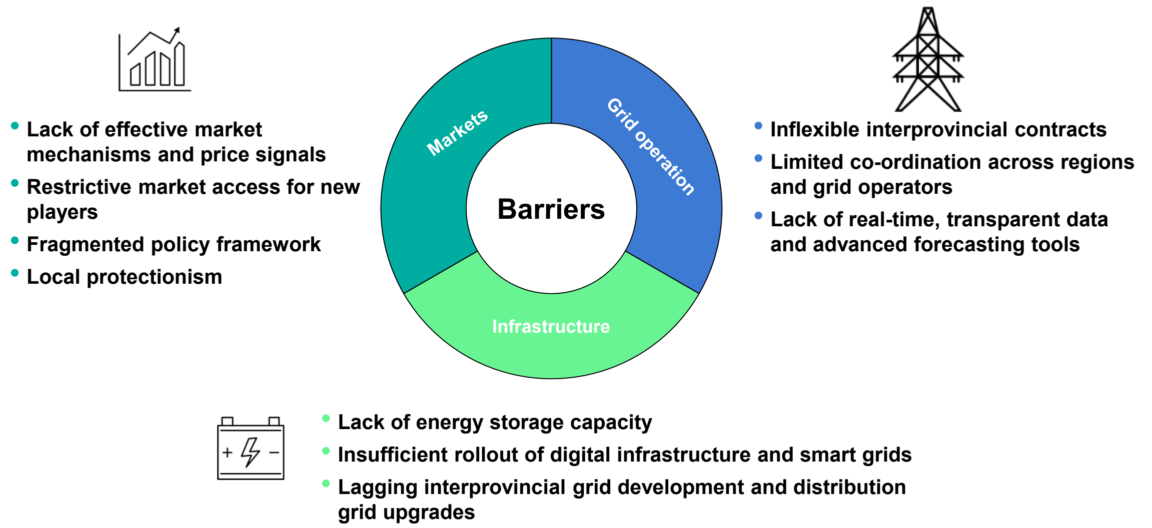
While China has made notable progress in building flexibility resources through administrative measures and technological advancements, key barriers remain that limit better use and further expansion. These obstacles primarily arise from fragmented regulatory frameworks, limited economic incentives and insufficient market mechanisms.

- **Lack of effective market mechanisms and price signals**. Price fluctuations are minimal in the few spot markets that are operational, and many suppliers and consumers are not exposed to real-time pricing. This lack of clear price signals provides little motivation for industries, businesses or households to participate in demand response or invest in energy storage. Additionally, some flexibility services remain undercompensated in China's current market structure.
- **Restrictive market access for new players**: High requirements and thresholds to participate in power markets can constitute a barrier for new players like VRE, VPPs and storage. The limited availability of market-based opportunities leads to low utilisation rates for flexible assets, typically storage assets paired with wind and solar, depriving them of potential revenue streams.
- **Fragmented policy framework**: China’s flexibility policies often vary across the country, leading to a lack of coherence in regulatory approaches. While some provinces and regions have been progressive in introducing TOU pricing and demand-response programmes, others lag behind. This fragmented regulatory

landscape creates inconsistencies in market entry for new flexibility providers and reduces the scalability of flexibility solutions.

- **Local protectionism**: Provincial governments often prioritise their own energy assets and the development of local flexible resources to ensure energy security and to boost the local economy, creating barriers to the expansion of interprovincial trade. This limits market integration and impedes efficient and flexible resource allocation across the country.
- **Grid operation and utilisation**: Although China's transmission network is an asset for system-wide flexibility, its current utilisation is limited by inflexible interprovincial contracts. These contracts prioritise firm supply agreements, reducing the system's ability to respond flexibly to real-time grid conditions. In addition, little co-ordination across regions and grid operators hampers efficient grid utilisation. The lack of widespread adoption of real-time data tools and advanced forecasting capabilities complicates grid operations, especially as VRE is integrated into the system.
- **Technological and infrastructure challenges**: Despite advancements in digital infrastructure, the large-scale deployment of technologies like energy storage, smart charging stations and smart grids remains a challenge. On the grid side, current and planned interprovincial capacity may not be sufficient to unlock the flexibility potential of the interconnected large balancing area, while distribution grid upgrades are lagging.

Barriers to maximising system flexibility in China



The barriers outlined above underscore the need for market-based mechanisms to unlock flexibility. Chapter 2 explores how well-designed power markets, including capacity payments, ancillary service markets and price signals for flexibility can address these challenges.

Chapter 2. Unlocking flexibility through power markets

Power markets as key to flexibility

As outlined in Chapter 1, China's power system faces growing flexibility needs driven by the rapid integration of variable renewable energy (VRE). The country has significant flexibility resources and is deploying more and more of them. As China is moving towards power markets, it is essential that these markets are designed to incentivise flexibility. Power markets, when designed effectively, can provide price signals that reflect the system conditions, ensuring the decisions made by the different market actors are aligned with the system needs.

This chapter explores how China's ongoing power market reforms – particularly in spot and ancillary services markets – are critical to achieving this flexibility. It examines the current state of market development, identifies opportunities for improvement and discusses the necessary steps to align market mechanisms with the country's evolving energy needs. The chapter concludes by addressing the key barriers that hinder full market-driven flexibility and setting the stage for Chapter 3, where specific policy recommendations are provided to address these challenges.

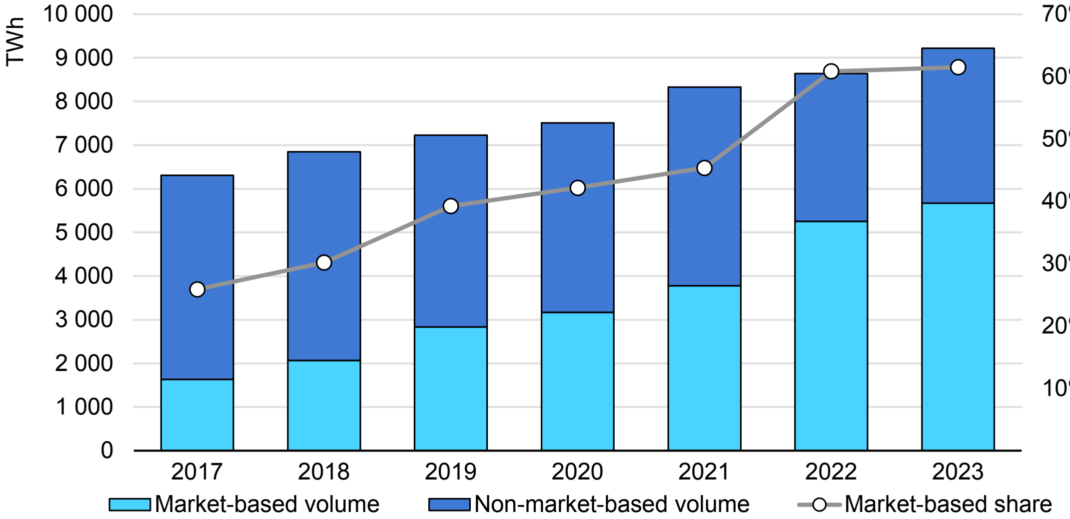
Current state of power markets in China and barriers to flexibility

China's power sector is undergoing a rapid transformation, with market reforms aimed at fostering competition and efficiency, improving system flexibility and integrating VRE sources. As of 2024, the country stands at a pivotal moment in its transition towards a sustainable and market-oriented energy system. While significant progress has been made, ongoing challenges highlight the need for continued reform to fully unlock flexibility through power markets.

Power market reforms and progress

Since 2015, China has introduced a series of reforms designed to liberalise its electricity markets and transition towards a more efficient, market-based system. By 2023, market-based transactions had grown to 5 670 TWh, representing 61.4% of total electricity consumption, against 60.8% in 2022. This marked the continuation of an upward trend, driven by national efforts to move away from centrally planned dispatch.

Evolution of market-based electricity volume and share in China, 2017-2023



Source: IEA based on data from the China Electricity Council.

Among the key reforms is the goal of establishing a unified national power market system by 2030, as set out in NDRC's Document No. 118 (2022) and re-stated as a priority during China's 2024 "Two Sessions" policy meeting. The 2024-2027 NEA's action plan emphasises the need for greater VRE integration, improved coal plant flexibility, demand-side management and expanded storage applications, all of which can be supported by power markets.

China's power market reforms are focused on aligning the country's electricity system with the goal of carbon neutrality by 2060. The way competitive markets, particularly spot and ancillary services markets, are introduced will be essential to ensuring that the system can handle the increasing variability in supply and demand caused by higher shares of wind and solar power.

Context of power markets deployment in China since 2015

Understanding the socio-economic and political context in China is crucial to comprehending the evolution of power market reforms since 2015. While high-level government documents emphasise the role of markets in the envisioned "modern energy system", China's interpretation of market roles differs from that of other liberalised power systems globally. In many countries, market deployment aims to drive economic efficiency and allow price signals to guide investments. In contrast, China views markets as tools for state planners to achieve top policy objectives such as dual carbon goals and energy security, all while maintaining control over their functioning and on prices.

Despite progress at various levels, the role of markets in China is often tightly constrained by administrative measures and new mechanisms that are introduced to quickly address issues but simultaneously add complexity to the structure of the power system. For example, historic high curtailment rates have been primarily mitigated through a full purchase obligation of renewable energy for grid companies, and provincial renewable consumption quotas. In addition, wholesale price volatility is managed through the implementation of price caps, while financial losses incurred by coal power plants are addressed with administratively set capacity payments.

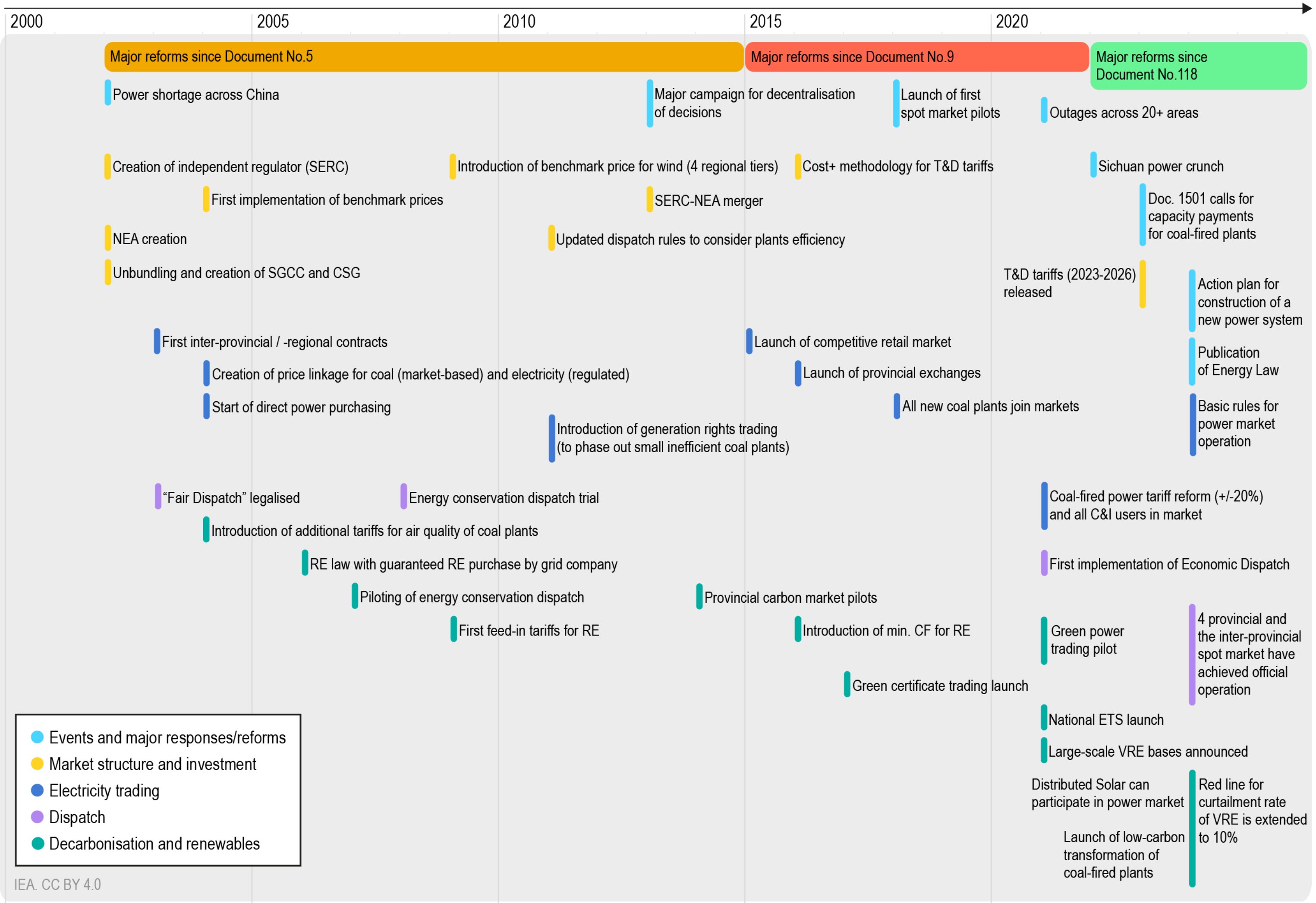
At the government level, there is still scepticism about the potential benefits of market reforms, driven by deep-rooted concerns about price volatility, energy security and job losses within the sector. The priority is to ensure the availability of affordable energy, while local stakeholders often view the introduction of spot markets as a risk for higher prices, potentially reducing the competitiveness of local industries.

Institutionally, reforms have historically been hindered by the dominant positions of state-owned enterprises (SOEs) and grid companies in electricity generation and distribution, with the fear than increased competition would undermine their power. For this reason, efforts to establish independent regulation and restructuring of SOEs should go hand in hand with the deployment of power markets.

However, there now seems to be stronger support for markets. As grid operations become more complex with the integration of new technologies, dispatching departments of grid companies are now pushing for electricity dispatch based on spot market results rather than on predetermined plans. Generation companies see the potential benefits that can be gained from MLT contracts and short-term trading on markets. In the context of the economic slowdown, it remains to be seen whether authorities keep pushing for markets.

International experience with power markets can assist China in constructing a unified national market system by 2030. However, simple replication of foreign models is unlikely to succeed without considering Chinese priorities and the authorities' preference for administrative intervention in power sector planning and investment.

Power sector reform milestones in China, 2002-2024



Notes: SERC = State Electricity Regulatory Commission. CSG = China Southern Power Grid. T&D = transmission and distribution. C&I = commercial and industrial. min. CF = minimum capacity factor. RE = renewable energy.

Medium- to long-term (MLT) contracts: dominant but inflexible

As of 2023, MLT contracts dominate China's electricity market transactions, accounting for over 90% of total traded electricity. Since 2023, large consumers and coal plants have been required to secure at least 90% of their annual consumption and generation, respectively, through MLT contracts.

In provinces and regions with operational spot markets using a centralised market model, MLT markets are theoretically intended to serve as a financial risk-hedging mechanism for producers and consumers. This means that those MLT contracts are not physically executed, except in some cases corresponding to inter-provincial transmission plans and priority generation agreements. This represents a shift from the historical approach whereby dispatch institutions planned production schedules based on contracted electricity volumes. However, the rigid pricing models[4] and the way these contracts are designed lead to a misalignment with real-time market needs.

In many instances, annual MLT contracts and their corresponding generation curves (sometimes according to pre-defined patterns, without possibility for tailoring) are negotiated once a year and cannot be renegotiated afterward nor transferred to other parties. This locks in prices and volumes for each time interval of the year (months, weeks, 24-hour periods), preventing any adjustment based on changing market conditions. Some plant operators thus face limitations in generating profits and renewable energy companies are exposed to risks due to the variability of their output. On one side, consumers tied to these contracts have limited opportunities to enjoy low prices on the spot markets when VRE generation is abundant. On the other side, the rigid nature of volume curve decomposition sometimes forces new energy producers to buy electricity at high prices on the spot market to fulfil contract terms.

However, in some provinces, recent efforts have pursued a better integration between the MLT and the spot markets, introducing buffer markets (e.g. four to two days ahead of real time) where market participants can adjust their contracted annual electricity volume for each time period through monthly and intra-monthly (weekly, daily rolling) transactions, enabling adjustments to the MLT contract curves and reducing contract execution deviations. This is the case for example in Gansu which has been operating on a three days ahead rolling mechanism since March 2024.

[4] The price of MLT contracts is set using a price difference model rather than dynamic market pricing, with a permitted fluctuation range of +/-20% around a benchmark price. The benchmark is calculated based on a standard coal power price to ensure the recovery of coal-fired power investment and operating costs.

Spot markets and economic dispatch

The rollout of spot markets is central to China's efforts to enhance system flexibility. As of mid-2024, 23 provinces and regions have initiated spot market pilots, with four provinces (in chronological order: Shanxi, Guangdong, Shandong and Gansu) and the inter-provincial spot market achieving official operation since the IEA's last update on the status of spot power markets in China.

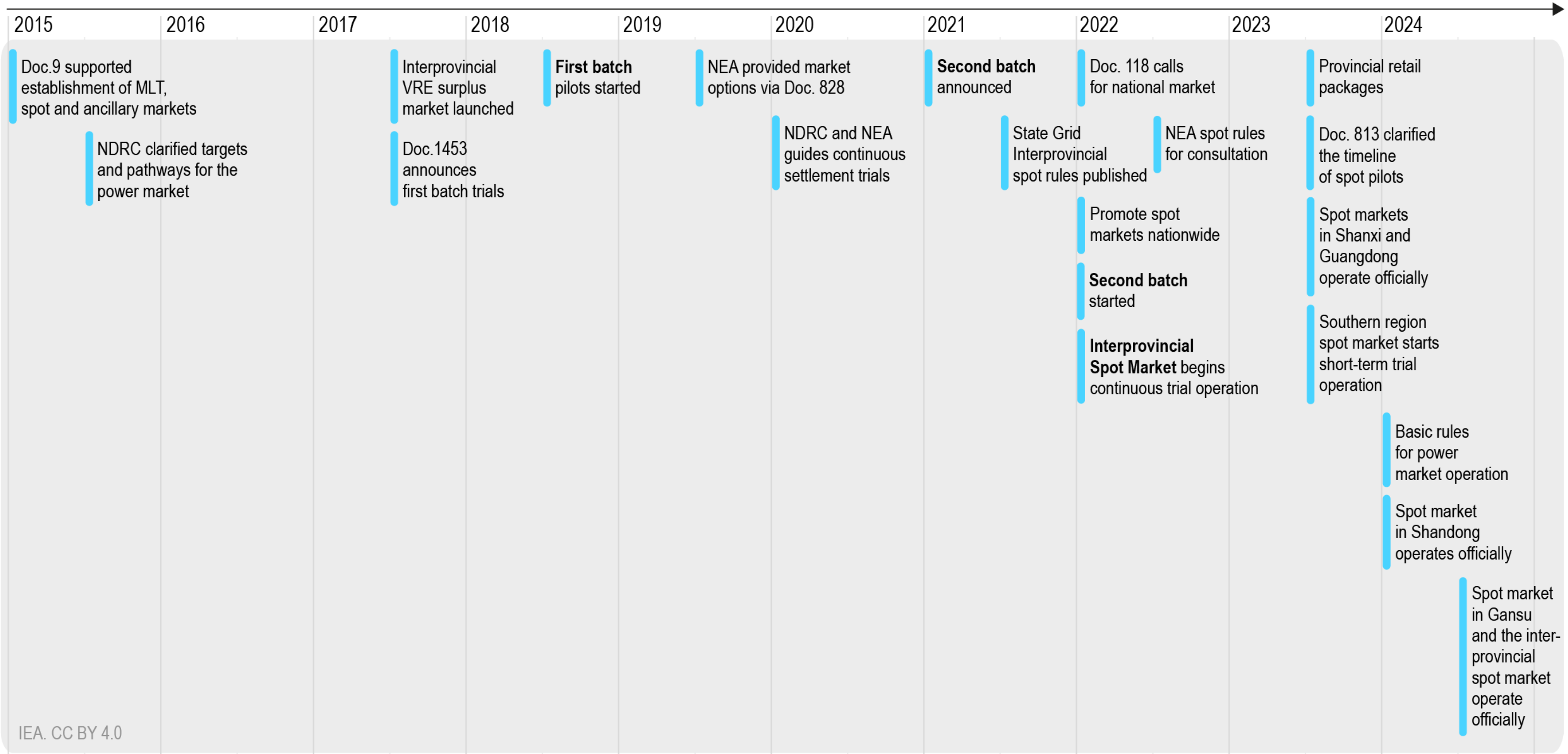
Spot markets are designed to implement security constrained economic dispatch, which prioritises the dispatch of the lowest marginal cost resources to meet demand. This is crucial for the integration of VRE, which has zero marginal costs but fluctuates based on weather conditions. In provinces and regions with operational spot markets, economic dispatch is gradually replacing administrative dispatch based on pre-agreed volumes, resulting in more efficient system operation.

Several issues remain to be solved to advance further spot market construction. Disparate access from new energy and new market players such as VPPs in spot markets prevent the formation of an effective market price signal that would guide investment where it is the most needed. For example, only Shanxi and Shandong provinces have effective arrangements for the participation of VPPs in their spot markets, although the spot market national rules released in 2023 push for it. When VPPs are able to participate, the role of VRE or distributed resources is most often limited to that of price takers, only bidding in the market for volume. To date, VRE participation in spot markets with both volume and price bidding is only possible in Shandong and Gansu.

The 2023 release of national spot market rules marks a critical step in formalising the operation of these markets. As part of the efforts aiming to optimise resource allocation, the interprovincial spot market within the State Grid's operating area officially started operation in October 2024, and the southern regional spot market covering Guangdong, Guangxi, Yunnan, Guizhou and Hainan provinces started short-term trial operation in December 2023. These achievements constitute key milestones towards achieving power market integration at the national level by 2030, but barriers remain for integrating spot and interprovincial spot markets. For example, only Inner Mongolia has incorporated interprovincial transactions into its market clearing process, with most regions still treating these transactions as firm input.

Some design features of spot markets will also gain in importance in the near future. Raising price caps and allowing negative prices facilitate a clearer understanding of the real value of electricity at each time. Reducing the minimum bid size enables smaller, aggregated resources to participate. Increasing the time granularity also helps accommodate the variability of wind and solar. Shortening the settlement periods allows for a more dynamic response to real-time conditions. Reducing the intraday market lead times (with a gate closure closer to real time) enables market participants to leverage updated VRE generation forecasts, minimising imbalances and reducing the need for reserves.

Timeline for the introduction of spot markets in China, 2015-2024



Shortening spot market settlement periods

In 2017, the European Commission introduced the Electricity Balancing Guideline, which calls for harmonising the imbalance settlement period at 15 minutes across the European Union. A subsequent cost-benefit analysis commissioned by the transmission system operators (TSOs) in the Nordic region found that reducing the imbalance settlement period to 15 minutes would provide better investment signals for flexibility and improved frequency quality, thereby triggering better use of interconnector capacity.

In 2021, the Australian Energy Market Commission (AEMC) shortened the settlement period from 30 minutes to 5 minutes to improve pricing efficiency and investment signals. Early evaluation of the implementation of this measure has revealed that it has encouraged investments in fast dispatchable assets like gas turbines and battery storage, while price volatility has remained mostly unchanged.

Progress of spot markets across China as of October 2024

Pilot phase	Description	Area
1.No plan	-	Beijing
		Tibet
		Eastern Inner Mongolia
2.Simulation without dispatch	A "shadow market" phase when market entities submit simulation bids to observe the normal function of the market operation system	Jilin
		Tianjin
3.Simulation with dispatch	"In due course", production and dispatch need to be carried out according to simulation results	Qinghai
		Xinjiang
		Shanghai
		Heilongjiang
4.Short-term trial operational with settlement	A "semi-functional" phase when market entities submit actual bids in a market operating under working plans or provisional rules over a fixed period of time (less than one month)	Southern Region (Guangdong, Guangxi, Yunnan, Guizhou, Hainan)
		Ningxia
		Chongqing
		Jiangxi
		Hunan

Pilot phase	Description	Area
5.Long-term trial operational with settlement	The spot market operates with settlement according to provisional rules for more than one month	Anhui Sichuan Jiangsu Liaoning Henan Shaanxi Hebei
6.Continuous trial operational with settlement	The spot market operates continuously with settlement according to provisional rules without an explicit end date	Fujian Hubei Western Inner Mongolia Zhejiang
7.Official operation	Permanent operation	Shanxi (Dec 2023) Guangdong (Dec 2023) Shandong (Jun 2024) Gansu (Sep 2024) Interprovincial Spot Market (Oct 2024)

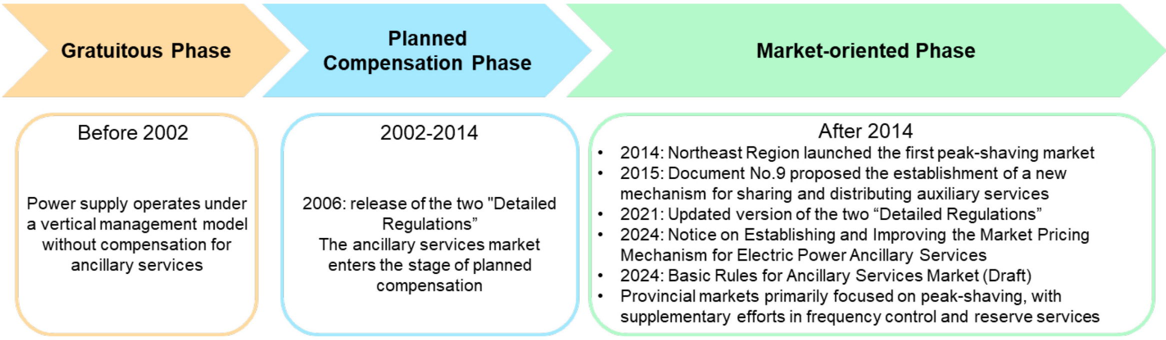
Source: IEA based on CEC, Blue Paper on the National Unified Power Market Development Plan (Draft).

Ancillary services: expanding product range and participation

Ancillary services are essential for maintaining system stability and security, especially as VRE integration increases. Traditionally, ancillary services in China focused on peak shaving (a service also called "peak regulation") and frequency regulation, but recent reforms are expanding the scope to include reserves, ramping services and frequency control. As spot markets develop and markets steer dispatch, the peak regulation will be progressively phased out. While most of these services were previously provided by thermal plants and hydro, new resources will be solicited as the power mix decarbonises.

There are now 30 provincial and 7 regional ancillary services markets in China. These markets have historically relied on regulated tariffs and fixed compensation for services like primary frequency regulation and reactive power support. However, recent policies signal a shift towards market-based pricing for these services. This transition is expected to drive greater participation from new resources, such as battery storage and demand-side aggregators. The Basic Rules of the Ancillary Services Market (Draft) released in October 2024 establish for the first time a national-level design framework that regional and provincial markets will be expected to comply with in the future.

The development of ancillary services markets



Notes : Two "Detailed Regulations": Regulations on the Management of Grid-Connected Power Plant Operations and the Management of Ancillary Services of Grid-Connected Power Plants (2006). Updated Two "Detailed Regulations": Regulations on the Management of Power Grid Connection Operations and the Management of Electric Power Ancillary Services (2021). Document No.9: Opinions on Further Deepening the Reform of the Electric Power System.

While some basic ancillary services are required to be provided for free by entities connected to the grid (including primary frequency regulation, basic peak shaving and basic reactive power regulation), other services are compensated through fixed tariffs or market-based mechanisms. Typically, compensated peak-shaving, frequency regulation, reserves and black start belong to the latter category. Since 2021, regulation states that inertia and ramping services can also be remunerated, but as of 2024, no province has yet introduced compensation for inertia. Shandong was the first province to introduce a market for ramping services, aimed at managing the growing variability caused by its large solar PV capacity (57 GW as of 2023).

Continued reforms and policy measures will be needed to create a unified, market-driven national power market system in China that fosters a healthy development of ancillary service markets. These reforms will need to harmonise the market fragmentation across provinces, co-ordinate ancillary services with other markets and mechanisms and increase competition by opening to new market players.

In provinces and regions without operational spot markets, the separate clearing processes for peak shaving, reserve and frequency regulation markets hinder rational bidding and efficient dispatch. The Spot Market Basic Rules envision a unified clearing process for these markets once the spot market is operational, with peak shaving eventually phased out. Coordination between provincial and regional level is also a challenge for optimal dispatch, as in most cases provincial demand for ancillary services is prioritised over inter-provincial demand for them, while optimising reserves at the regional level would be more cost effective. Moreover, new market players, such as battery storage and VPPs –despite being theoretically eligible to provide ancillary services –encounter obstacles like bidding caps and varying requirements that prevent them from fully engaging in the market. Only Shanxi and Shandong have fully integrated VPPs into their spot and ancillary services markets.

International experience with new services to address stability in systems with high shares of converter-connected resources

By 2030, some regions of China with high penetration of wind and solar PV will face emerging challenges related to grid stability. Traditional synchronous generators, like thermal power plants, inherently contribute to system strength, providing inertia, voltage support and fault current. However, VRE resources, typically connected through converters, do not possess these characteristics. As the share of VRE increases and conventional generators are phased out, maintaining grid stability necessitates the introduction of new system services.

Fast Frequency Response (FFR) services are situated between inertial response and traditional frequency control reserves. They can be activated within seconds to stabilise frequency after a disturbance. This reduces the need for inertia and can be provided by battery storage and demand response through fast load disconnection. FFR services were introduced in the Nordic system in 2020.

Modern converter controls can emulate inertia, enabling battery storage and VRE plants to contribute to frequency stability. This grid-forming capability allows these resources to support the grid even with reduced synchronous generation. Battery projects in South Australia and Ningdong (Ningxia) demonstrate the use of grid-forming converters to provide inertia.

Dedicated assets like synchronous condensers and STATCOMs (Static Synchronous Compensators) can be deployed to provide voltage support. Synchronous condensers, essentially synchronous machines without a prime mover, inject reactive power to regulate voltage, while STATCOMs use power electronics to achieve similar results. Chile has implemented an auction for voltage control services, leading to investments in synchronous condensers.

System operators such as NESO in Great Britain are exploring stability markets to procure stability services more efficiently. These markets allow various resources, including synchronous condensers, batteries and demand response, to compete in providing inertia, fault current and voltage support.

Cross-border balancing platforms in the European Union

Balancing refers to the action and processes through which transmission system operators (TSOs) maintain the system frequency within a stability range. Doing so at the European level can be more cost-efficient than using only resources available nationally in EU member states (MS). Therefore, the EU target model aims at integrating balancing energy markets across borders. This is currently done through the operation of four European balancing platforms:

- the TERRE platform for replacement reserves (RR);
- the MARI platform for manual frequency restoration reserves (mFRR);
- the PICASSO platform for automatic frequency restoration reserves (aFRR);
- the IGCC platform for imbalance netting (IN), to avoid the simultaneous activation of aFRR in opposite directions.

TSOs are responsible for these platforms and their operation (activation optimisation, TSO-TSO settlement, capacity management).

Connecting to these platforms requires TSOs to use standard products and to adapt their local market designs beforehand. A lack of harmonisation in the TSO operation zone can hinder the functioning of these regional platforms. For example, the case of the Italian TSO Terna temporarily leaving the PICASSO platform in March 2024, a few months after its connection, is attributed to the different requirements in Italy to provide aFRR, which led to abnormal price volatility on the market.

The integration of balancing energy markets is made progressively with accession roadmaps for all EU MS for MARI and PICASSO platforms. Only TERRE will stop operating in 2026 due to the evolution of the intraday cross-zonal gate closure time to 30 minutes, which is incompatible with the current RR provision process.

Platforms	TERRE (RR)	MARI (mFRR)	PICASSO (aFRR)	IGCC (IN)
Participants (as of June 2024)	7 TSOs	6 TSOs (plans to expand to 9 more by end of 2024)	7 TSOs (plans to expand to 10 more by end of 2024)	31 TSOs
Go-live year	2020	2022	2022	2021
Economic surplus generated in 2023	281 M€	9 M€	137 M€	621 M€

Note: the economic surplus corresponds to savings for final consumers and Balancing Responsible Parties (BRP) for the IGCC platform, while for the other platforms include BRP and Balancing Service Providers (BSP) surplus as well as congestion rents.

Source: IEA based on data from ENTSO-E.

Ancillary services (AS) in China and their main characteristics

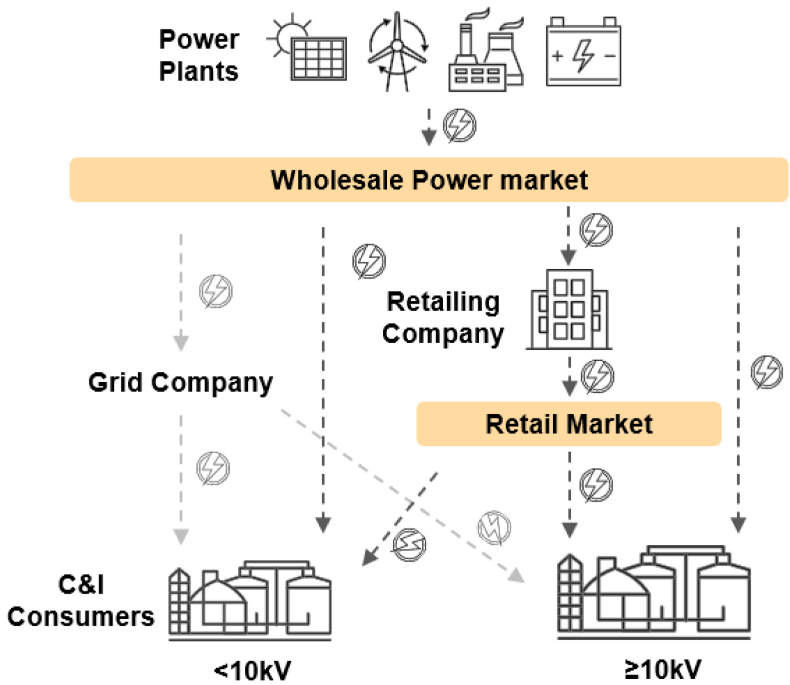
Service	Characteristics	Pricing mechanism	Service providers
Peak shaving	Units receive compensation for adjusting their operating power and make space for other generation. Most mature and widespread AS. Phased out where spot markets are operational.	Market-based, or fixed compensation paid monthly.	Thermal and hydropower units. Extended to demand-side providers in some regions.
Frequency regulation	Units adjust their output to ensure stable grid frequency. Dispatch based on units' overall performance. Independent clearing and could be cleared with spot if in operation.	No or fixed compensation for primary frequency regulation. Mostly market-based for secondary frequency regulation. Single pricing mechanism based on the design parameters of the local coal power unit with the best performance.	All types of units.
Reserve	Units provide backup power to maintain reliability during unexpected outages or increased demand. Independent clearing and could be cleared with spot if in operation.	Market-based. -Reserve mode: units operate below their maximum adjustable output and are paid for the reserve capacity. -Dispatch mode: units are paid upon activation.	Thermal and hydropower units, new energy storage with adjustable capacity.
Ramping	Units provide upward or downward adjustment of their output to balance load during periods of rapid fluctuations. Independent clearing and could be cleared with spot if in operation.	Market-based (only operational in Shandong).	Power generation units >100 MW (excluding pumped storage), independent energy storage, VPP.
Demand response	Peak shaving services dedicated to demand-side resources.	Market-based (Guangdong, Jiangsu), or fixed compensation through out-of-the market mechanism.	Aggregators and entities above 0.3 MW (Guangdong).

Retail markets: a shield for consumers against spot prices variations

The retail market is the largest channel for electricity purchases. While outside of China these are primarily designed to protect households from wholesale price fluctuations, most large consumers in China also procure electricity through retail markets, with limited participation in wholesale market-linked tariffs.

Until recently grid companies served all users at government-set tariffs. Reforms since 2015 have gradually opened the retail market, allowing commercial and industrial (C&I) consumers to purchase electricity from retailers rather than grid companies. NDRC Document No. 118 (2022) announced that all C&I consumers would need to transition to market-based purchases, either through retailers or directly from the wholesale market. However, very few C&I consumers directly participate in the wholesale market. For example, nearly all C&I consumers in Guangdong purchased electricity through retailers in early 2024. Rules for access to the wholesale market differ by regions. Some provinces require minimum annual consumption thresholds (10 GWh in Guangdong and Qinghai, 5 GWh in Fujian), while others have removed these restrictions (Sichuan and Xinjiang).

Power markets access for commercial and industrial (C&I) consumers



IEA. CC BY 4.0.

Note: Light grey arrows indicate that grid purchasing serves as a transitional solution and will be phased out gradually in the future.

Despite these reforms, only 12.5% of retail transactions in Guangdong were linked to spot and/or monthly trading market prices in 2023, only slightly exceeding the 10% requirement. Most C&I users prefer to pay a premium for fixed-price contracts to purchase the majority of their consumption, shielding themselves from market volatility. The slow adoption of spot market-linked tariffs means that retail markets are not yet driving significant flexibility.

Retail tariffs packages

Category	Content	Characteristics	Flexibility
Fixed-price	An agreed-upon fixed price without TOU constraint	No risk of price increases, no benefit from price decreases	-
Fixed-price (TOU)	An agreed-upon fixed price with TOU is applied	No risk of price increases, no benefit from price decreases	**
Market-linked	An agreed-upon surcharge or discount is applied based on the spot market price	Risk of price increases and possible benefit from price decreases	**
Price-linked	Price fluctuates with the price of primary energy, MLT price, etc.	Mostly linked with the price of coal considering the impact of coal-fired plants on MLT market	-
Revenue-sharing	Retailers and consumers share gains or losses based on an agreed-upon share and benchmark price	Partial hedging against price increases and benefits from price decreases	*
Green electricity	An environmental premium is added on top of electricity price which is determined by other packages	Consumers receive a green certificate as proof of green power consumption	-

* indicates an indirect impact, ** indicates a direct impact on system flexibility by influencing user behaviour, and – indicates no significant impact.

Time-of-Use (TOU) Tariffs as an efficient flexibility tool

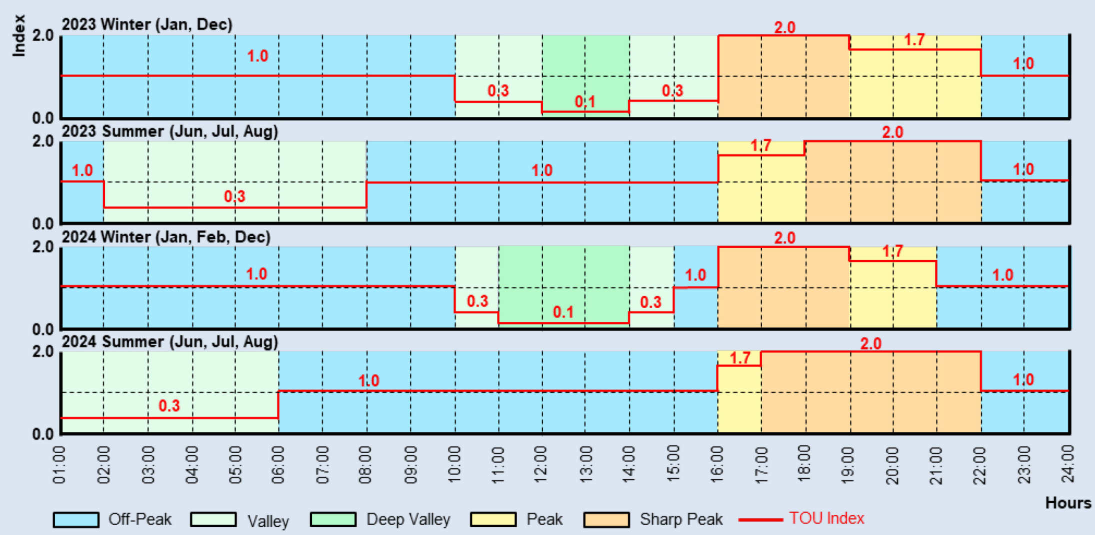
NDRC's 2021 Document No.1093 mandates TOU for all C&I consumers. By 2023, 29 provinces had adopted TOU policies, though the structures vary. Provinces with high power demand, such as Shandong and Jiangsu, have introduced "sharp peak" pricing, while regions with growing VRE installations, like Inner Mongolia and Xinjiang, have implemented "deep-valley" pricing. With the increasing share of VRE, TOU tariffs are being aligned more with the net load curve rather than with the traditional load curve.

Time-of Use pricing updates in Shandong

Since January 2023, Shandong province has implemented a dynamic adjustment mechanism for TOU electricity pricing, updated annually. During high VRE generation months like April and November, the policy mandates that the price difference between peak and valley periods must exceed 60% compared to off-peak prices.

With 57 GW of solar PV installed by the end of 2023 (the highest in the country), Shandong's TOU update extended the deep-valley period to better accommodate midday VRE output. In 2023, the price difference between minimum and maximum rates reached RMB 759 (USD 108)/MWh, effectively incentivising users to shift consumption to off-peak times. This resulted in an estimated midday demand increase of 3.5 GW, along with 2 GW of load shifted from peak evening hours.

Shandong TOU pricing plans during the winters and summers 2023 and 2024



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Source: IEA based on data from the State Grid Shandong Electric Power Company.

Residential pricing: a sensitive issue

Residential consumers typically place a high value on stable and predictable electricity bills and are not willing to be exposed to wholesale prices. However, residential consumers can still effectively be mobilised to provide demand response through well designed TOU retail rates, with critical peak pricing programmes involving direct load control of household appliances (particularly for air conditioning and water heating) during scarcity events.

In China, while smaller in volume, residential demand plays a significant role during peak periods. In provinces like Zhejiang, Hubei and Sichuan, air conditioning constitutes 40-50% of peak demand, with more than half coming from households. However, current pricing does not tap into this flexibility potential. Residential users, along with agriculture and public services, are shielded from market prices and purchase electricity from grid companies at administratively set tariffs.

Cross-subsidies keep residential prices low by having C&I users bear the cost difference, reducing households' price sensitivity while increasing the burden on industries. To encourage energy conservation, tiered pricing was introduced in 2011 so that higher consumption beyond a certain threshold is charged at higher rates. Tiers are based on either monthly or annual consumption, therefore playing no role in demand shifting and only encouraging energy savings. Additionally, calculating charges based on total monthly volumes can discourage the electrification of certain uses, like heating, as installing devices like heat pumps could push households into higher tariff brackets.

In 2021, NDRC's Document No. 1093 promoted TOU pricing for residential consumers "according to procedures" and "where conditions permit", and some provinces, like Shandong and Jiangsu, have implemented it for households and residential EV charging. TOU pricing is an effective tool for shifting demand but is currently opt-in (requiring residents to voluntarily apply for enrolment), and the lack of widespread TOU meters limits its broader impact.

Synergies between energy efficiency and flexibility

China's efforts to reduce energy intensity through the "Dual Control" policy and the energy efficiency targets set in the last two Five-Year Plans, align with the goals to increase renewable capacity and develop the corresponding flexibility. The announced shift from controlling total energy consumption to capping total emissions (from the 2026-2030) also has significant implications for industrial emissions, and further reinforces the need for energy efficiency measures.

Energy efficiency reduces overall energy consumption, helping lower peak demand and decreasing the magnitude of fluctuations that the power system needs to manage. At the same time, the replacement of inefficient fossil fuel technologies with heat pumps and EVs, which are both energy-efficient and can serve as flexible loads or storage solutions, further enhances system flexibility if managed well.

Energy efficiency policies should prioritise clean, sustainable alternatives. For instance, connecting coal-fired CHP plants to district heating improves short-term efficiency but risks locking in coal use, limiting the shift to efficient electric heating.

In the building sector, improving building envelopes and using energy-efficient appliances can significantly reduce energy demand and emissions. A notable share of the projected increase in cooling-related electricity demand in China could be mitigated through policies incentivising highly efficient air conditioners coupled with building insulation and well-designed neighbourhoods and cities. Policies like the Green Building Action Plan and the Energy Efficiency Standards for Buildings are driving these improvements.

Demand response programmes are also emerging in China, encouraging consumers to adjust their electricity use based on price signals or grid conditions. The convergence of energy efficiency and demand flexibility is further enabled by digital technologies, such as smart meters and thermostats. These technologies create opportunities for consumers to actively participate in the power system, enhancing its reliability and cost-effectiveness.

Capacity payments for coal plants: ensuring adequacy at the risk of price distortions in markets

Discussions around capacity markets have gained momentum after the 2021-2022 summer power crises, when energy security was particularly at risk. In 2023, historic low hydro availability combined with record heatwaves highlighted the challenges of ensuring sufficient capacity during system stress, a growing concern in the face of climate change. Recent policy documents prove that this topic is high on the agenda, with references to "market-oriented capacity mechanisms" (January 2022), and "capacity trading" added for the first time (May 2024) as a transaction type in the updated rules for the operation of the electricity market.

In January 2024, capacity payments for coal power plants were introduced. In addition to being remunerated for their electricity generation, the mechanism guarantees a monthly payment to coal generators based on their capacity, corresponding to a certain percentage of recovery of their annual fixed costs.[5] Both existing and new coal power plants are eligible without any form of competition, provided that they meet flexibility, environmental and efficiency requirements (which are yet to be detailed in an upcoming communication by the NEA) and that they are not captive plants. The capacity payment is recovered through the electricity tariffs of C&I users.

[5] A nationally determined benchmark of fixed costs was set at RMB 330/kW per year, with coal-fired power plants receiving between 30 and 50% of this amount depending on the province. Assets located in provinces with a higher share of renewables will receive more, as their operation hours are lower.

With this measure, the government aims to support coal generators in transitioning from base load power to a supporting role for renewables, addressing financial losses caused by declining operational hours. With new investments in coal driven by energy security, these payments also seek to limit the risk of stranded assets. While they have the advantage of the simplicity of implementation, several design flaws could impede market efficiency and energy security.

First, the national payment excludes other potential capacity providers like storage and demand response, which could deliver reliable capacity more cost-effectively and with lower emissions. In Europe, for example, more than 5 GW of battery energy storage have secured capacity market contracts in the past three years. Including batteries and other technologies in capacity markets can secure long-term revenues for these projects. Other capacity remuneration mechanisms (CRM) exist in China, such as capacity tariffs for pumped hydro storage and, in some provinces, CRM for storage and gas turbines, but they are all siloed by technology, creating disparities among flexible assets and limiting competition across technologies.

Second, flat payments made to coal plants could lead to price distortion in MLT and short-term markets, with coal assets bidding lower than their marginal cost. At the same time, they can directly encourage investments in new coal capacity, exacerbating overcapacity – a known risk in capacity remuneration mechanisms, observed in several eastern US jurisdictions.

Third, the lack of competition among capacity providers (e.g., through auctions) induces a risk of paying beyond what is really necessary to ensure energy security. In jurisdictions where capacity markets are in place, competitive auctions typically help identify the most cost-effective resources to meet a system operator's capacity targets.

Finally, the absence of performance-based remuneration and the limited penalties for unavailability fail to incentivise reliability. Lessons can be learnt from the PJM market in the eastern United States, where a cold snap in 2014 led to widespread outages because cleared resources on the capacity market were not able to deliver. While PJM auction rules required that these units be available, the penalty for non-performance was trivial compared to the revenues received. Since then, PJM has significantly increased penalties for non-performance.

Ensuring resource adequacy throughout China's power system transformation

While China currently has abundant generation capacity, the challenge lies in ensuring enough dispatchable capacity to manage a power system with high shares of VRE. The transition to economic dispatch and the development of well-functioning electricity markets that value flexibility can ensure the right level of dispatchable capacity that includes flexible resources like gas, hydro and emerging low-carbon solutions, which are essential to balancing the variability of wind and solar power.

Economic dispatch, alongside the establishment of robust spot markets, ensures that the most efficient and flexible resources are prioritised, including low-carbon options. This shift will likely reduce the operating hours of less-efficient coal plants, potentially leading to their closure. To manage the orderly exit of these plants, policy interventions such as plant repurposing may be necessary.

Capacity remuneration mechanisms (CRMs) can compensate essential dispatchable plants ensuring system reliability without limiting the participation of flexible resources like storage and demand response in the spot market. A technology-neutral CRM increases competition and innovation by allowing various flexibility resources to compete for capacity procurement.

Grid infrastructure plays a critical role in enhancing both resource adequacy and flexibility. Reinforcing interconnections between regional grids and expanding transmission capacity can help balance supply and demand over larger areas. This allows better integration of VRE from resource-rich regions and improves the overall system's flexibility and reliability.

Main characteristics of capacity remuneration mechanisms in selected jurisdictions

	China	United Kingdom	Western Australia	PJM (USA)	Colombia	Japan	France
Type of mechanism	Fixed capacity payments	Capacity market with centralised auctions	Reserve Capacity Mechanism with decentralised capacity obligation	Mandatory centralised uniform price auction	Firm energy obligation auction*	Capacity market with centralised auctions**	Decentralised capacity obligation
Start year	2024	2018	2004	2007	2008	2020	2017
Technology - agnostic	Only coal power plants	✓	✓	✓	✓	✓	✓
Basis of payments	MW	MW	MW and MWh	MW	MWh	MW	MW
Capacity price	30 to 50% (depending on the province) of a nationally determined fixed rate set at RMB 330/kW per year	Use of a demand curve to set the price paid to participants in capacity auctions	Set administratively every year, based on the capital costs of a new build gas plant	Use of a demand curve to set the price paid to participants in capacity auctions. Locational pricing	Use of a demand curve to set the price paid to participants in capacity auctions	Use of a demand curve to set the price paid to participants in capacity auctions	Certificates are traded with a price cap, over the counter or through organised exchange
Market-based	-	✓	✓	✓	✓	✓	✓
Procurement timeline	-	4 and 1 year-ahead auctions	3-years ahead	3-year-ahead auctions	4-year-ahead auctions	4-year-ahead auctions	Continuous operation of market until delivery
Penalties or performance incentives	Progressive payment reductions for underperforming plants	Financial penalties during system stress events	Refund of capacity payments in case of unavailability, and redistribution to other capacity credits holders	Significant penalties in case of unavailability, and bonuses for over-performance	Difference between the actual production and the firm energy obligation is settled on the spot market	Financial penalties in case of unavailability	Financial penalties in case of unavailability

* Reliability obligations become operative when the spot price reaches a scarcity price set by the regulator.
** Long-term capacity auctions dedicated to low-carbon resources were also introduced in Japan in 2024.

Unlocking flexibility through market mechanisms

Building new assets to provide the needed flexibility in a cost-effective way will require an update of current market designs**.** Well-functioning markets deliver incentives and a fair distribution of revenues to technologies contributing to system security. Rules must reward resources for their actual contribution to secure operation, instead of an expected or average contribution.

Analysis of different market design choices was carried out to quantitatively evaluate China's future power system in 2030. The national-level demand and supply values from the Announced Pledges Scenario (APS) of the IEA World Energy Outlook (WEO) were disaggregated into eight regions, with transmission connections between them. A number of scenarios were devised to illustrate the impact of different market design choices on the future power system, investigating the participation of demand-side and supply-side resources. On one hand, the scenarios elucidated how market design can achieve more efficient utilisation of assets already active in the power system. On the other, they were useful in investigating how market design can valorise and integrate new asset types, such as demand response and storage, into the power system. The 2030 APS includes demand shifting across sectors such as agriculture and households, representing an expansion of current low levels of demand participation in some sectors through closer alignment to market prices.

Scenarios investigating different levels of power system flexibility

	2022	Partial ED, volume coupled market	Partial ED, inter-regional surplus market	Low AS market participation	Inter-regional surplus market	Low Commercial & Industrial shifting	No Commercial & Industrial shifting	Low EV & Residential shifting	No EV & Residential shifting	**2030 APS (full ED, volume coupled market)**	Full AS market parti-cipation
Industrial demand shifting	Limited	Yes	Yes	Yes	Yes	Reduced	No	Yes	Yes	Yes	Yes
Commercial demand shifting	No	Yes	Yes	Yes	Yes	Reduced	No	Yes	Yes	Yes	Yes
Residential demand shifting	No	Yes	Yes	Yes	Yes	Yes	Yes	Reduced	No	Yes	Yes
Agriculture demand shifting	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Passenger EV demand shifting	No	Yes	Yes	Yes	Yes	Yes	Yes	Reduced	No	Yes	Yes
Other transport demand shifting	No	Yes	Yes	Yes	Yes	Yes	Yes	Reduced	No	Yes	Yes
Demand AS participation	No	No	No	No	No	No	No	No	No	No	Yes
Storage BtM charging	No	VRE Only	VRE Only	VRE Only	VRE Only	VRE Only	VRE Only	VRE Only	VRE Only	VRE Only	VRE Only
Storage FtM access to AS markets	No	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Dispatch	Fair Dispatch all regions	FD some regions	FD some regions	ED with constraints	ED with constraints	ED with constraints	ED with constraints	ED with constraints	ED with constraints	ED with constraints	ED with constraints
Interregional coordination /trade	Historic flows	Volume coupled market	Surplus Market	Volume coupled market	Surplus Market	Volume coupled market	Volume coupled market	Volume coupled market	Volume coupled market	Volume coupled market	Volume coupled market

Notes: ED= economic dispatch. FD= fair dispatch (plants are allocated a number of full-load hours over the year). BtM = behind-the-meter. FtM = front-of-the-meter. TOU= time-of-use tariffs. "Surplus market" refers to a situation where local markets with different designs co-exist while the whole interconnection is supported by a national market where excess generation is traded on a voluntary basis. "Volume-coupled market" refers to a situation where interconnection flows are optimised compared to the surplus market, while keeping local autonomy in price formation and dispatch (no price coupling).

Battery storage contribution to flexibility depends on market design

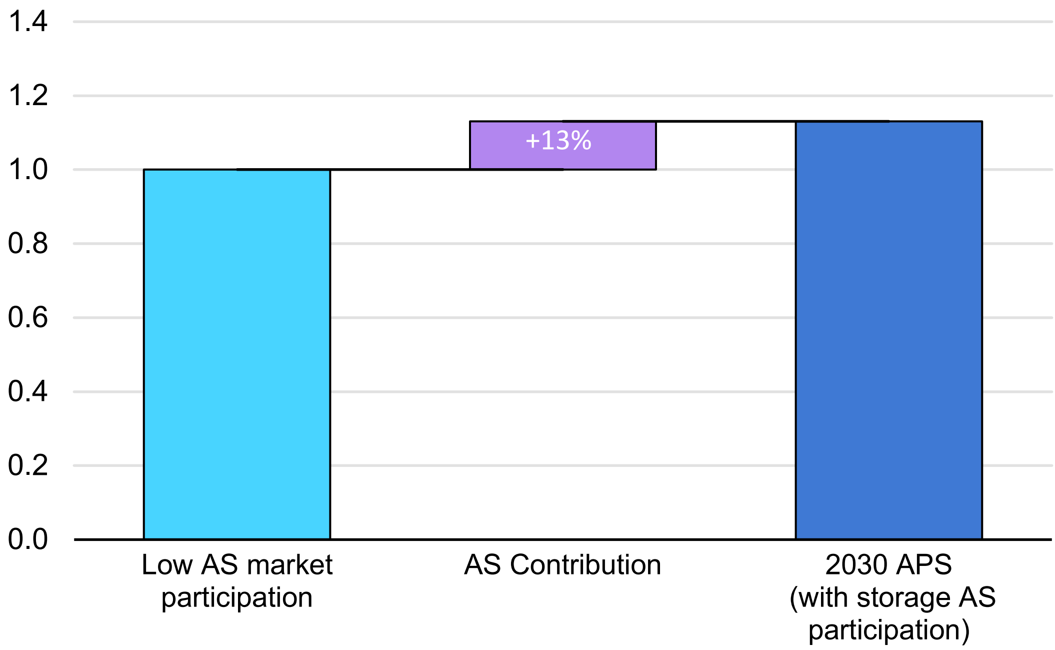
Grid-scale battery energy storage has a key role to play in China's future power system. Globally, China dominates the refining of nearly all critical minerals needed for battery production, leaving it well placed to take advantage of this technology. Battery storage has achieved sufficient cost reduction to be bankable in many global energy markets and has demonstrated a valuable contribution to system flexibility, both in wholesale energy and ancillary service provision. With faster ramping rates than conventional flexibility providers and fast frequency response ability, batteries can help accommodate VRE generation provided that markets are well designed and send appropriate price signals.

National-level policy promotes battery and other "new energy" storage participation in spot markets as independent entities. Existing implementation differs between provinces: some permit independent storage operators to bid volume only, or both price and volume (Shandong, Shanxi, Guangdong); some provinces have introduced capacity-based compensation for storage (Shandong, Inner Mongolia), while most provinces have still not opened their market to those new players.

Although well intentioned, mandatory storage requirements for VRE project developers that focus merely on capacity and energy ratios – without considering low utilisation and limited market access – can create skewed incentives. Project developers are likely to shield projects from limited storage revenue potential by minimising capital expenditure on mandatory storage systems, yielding a lower-quality storage fleet offering less value to the power system.

Effective battery participation in markets relies upon price signals accurately valorising energy across different timescales, unlocking the potential for underutilised batteries to provide price arbitrage. Ancillary service markets can provide vital additional revenue streams to battery operators, improving the business case of those assets and incentivising investments in higher-quality storage equipment.

Increase in energy dispatched by battery storage with access to ancillary services (AS) markets compared to a situation with limited access to AS markets, in China in the Announced Pledges Scenario in 2030



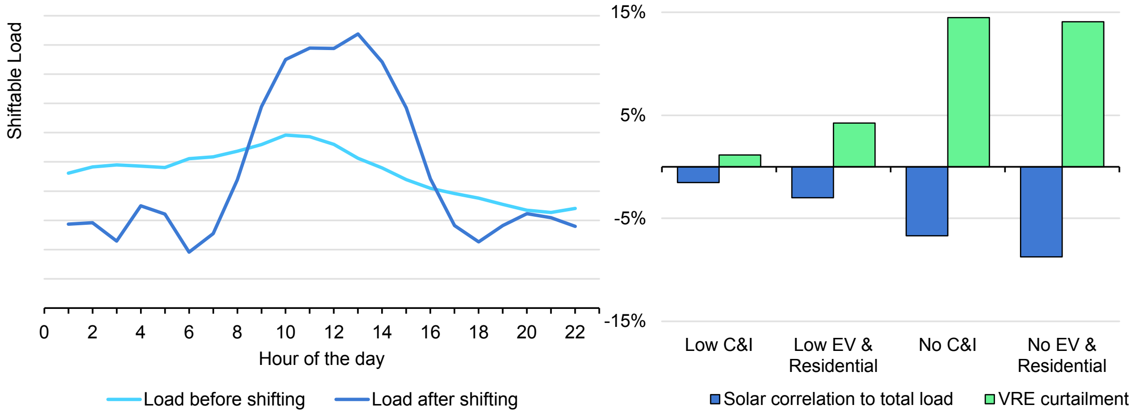
Note: The low AS market participation scenario is scaled to 1 to show the proportional increase unlocked by AS market participation.

Model results demonstrate that effective participation in ancillary service markets improves battery participation (energy dispatched and energy committed) by 13% in 2030, against wholesale participation alone. As market signals become more reflective of economic value, ancillary service markets can be further optimised to allow flexible resources such as batteries to bid different proportions of their available capacity into different markets (“revenue stacking”). This delivers price signals about the relative value of different markets, based on their scarcity at different times, and provides important mid-term investment signals to investors and decision-makers.

Demand-side flexibility becomes critical to complement supply-side flexibility

Demand-side flexibility market participation can complement supply-side measures and further align demand and supply. China’s strong solar capacity growth will yield an abundance of solar generation around midday. Shifting flexible demand towards this period mitigates the (in any case, considerable) need for energy storage to shift this supply to other times of day. Unlocking the participation of demand beyond industry to include commercial, residential or agricultural load will be a key driver of VRE integration, allowing the system to proactively adapt demand to better align with intermittent VRE and reduce VRE curtailment. Scenarios in which aggregated demand has more limited access to markets exhibit a weaker correlation between solar generation and total load, as well as greater VRE curtailment. Making better use of available solar PV generation can reduce the occurrence of low and negative prices around the solar peak observed in some international markets and provinces in China (e.g. Shandong), which can undermine the bankability of new renewables projects.

Daily profile of shiftable load before and after shifting, in the Announced Pledges Scenario in 2030 (left) and VRE curtailment and the correlation of solar generation to total load under scenarios with different demand shifting potential, relative to the Announced Pledges Scenario in 2030 (right)



Notes: C&I = commercial and industrial. EV = electric vehicles. Relative to the 2030 APS, “Low” scenarios have reduced shifting potential in the respective sectors, while “No” scenarios have no shifting potential in the respective sectors. Scenario settings are not incremental and are in ascending order by VRE curtailment in the right-hand graph.

The United States Federal Energy Regulatory Commission (FERC) sought to facilitate better access to markets for demand aggregation in 2020 by requiring transmission operators to define eligibility criteria for aggregators. The size requirement for aggregators was brought down to 100 kW of total aggregated power, to encourage the participation of smaller entities. Moreover, the order stipulated the broadest feasible locational limits and explicitly allowed the aggregation of assets with differing physical and operational characteristics. Pilot projects in Europe under the RESONANCE project show progress in standardising the aggregation and management of small-scale distributed assets, addressing the challenges of ensuring technical compliance, thereby maximising the possible asset base.

Time-varying network charges, which fluctuate throughout the day to reflect the actual cost of using the grid at different times, can further encourage consumers to adjust their electricity consumption patterns in response to price signals. For instance, during periods of high VRE generation (e.g., sunny midday for solar PV), network charges can be lowered, incentivising consumers to increase their electricity consumption. Conversely, during periods of peak demand or low VRE generation, network charges can be raised, discouraging consumption and alleviating strain on the grid. These variable network charges support flexibility and can also promote self-consumption and storage, as illustrated by the experience of Australia and some European countries, like Norway and Spain.

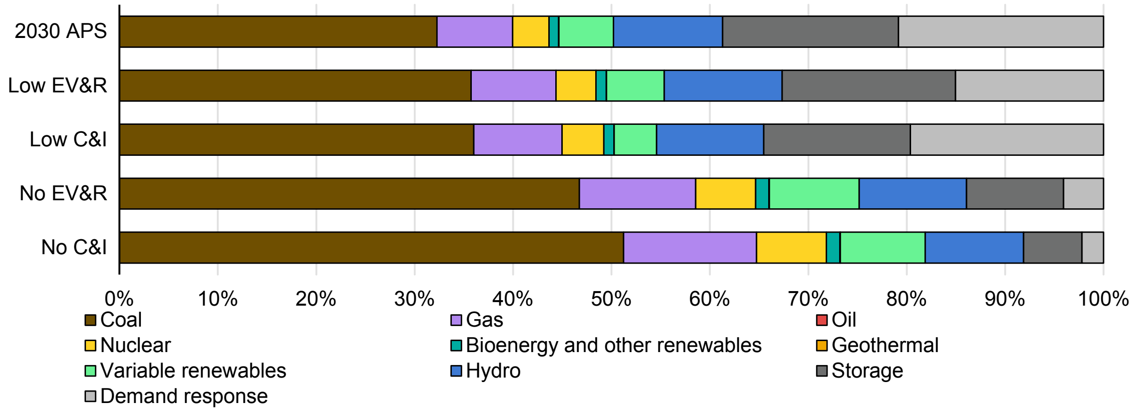
Household demand flexibility can be harnessed by smart appliance management

The TOU tariffs for households trialled in some provinces are a positive step in providing price signals for end users. Comfort and convenience are key criteria in the consumption decisions of residential consumers historically accustomed to flat-rate tariffs, while industrial and commercial users primarily view electricity consumption through the lens of cost optimisation. Economies of scale permit commercial users to devote far more time and resources to electricity consumption decisions than most residential users can devote.

Achieving high participation rates in TOU tariffs therefore requires a process of behaviour change and brings uncertainty about the level of response in different situations. Direct control of household appliances by the system operator, within clearly defined boundaries to ensure consumer protection, can enable this flexibility while reducing the associated uncertainty.

If markets do not support the active shifting of household appliances and EV flexibility, the power system will miss out on this large potential in flexibility provision by 2030, with EV and residential flexibility making a similar contribution to commercial and industrial shifting. The contribution to ramping needs from coal generation increases markedly in scenarios with limited or no shifting, from around one-third of ramping energy required in 2030 in the APS.

Contribution to ramping by technology in China in various scenarios in 2030



Notes: Commercial and Industrial (C&I) demand includes service, industrial and agricultural demand. EV & Residential (EV&R) demand includes passenger EV and residential demand.

Demand Flexibility Service in Great Britain

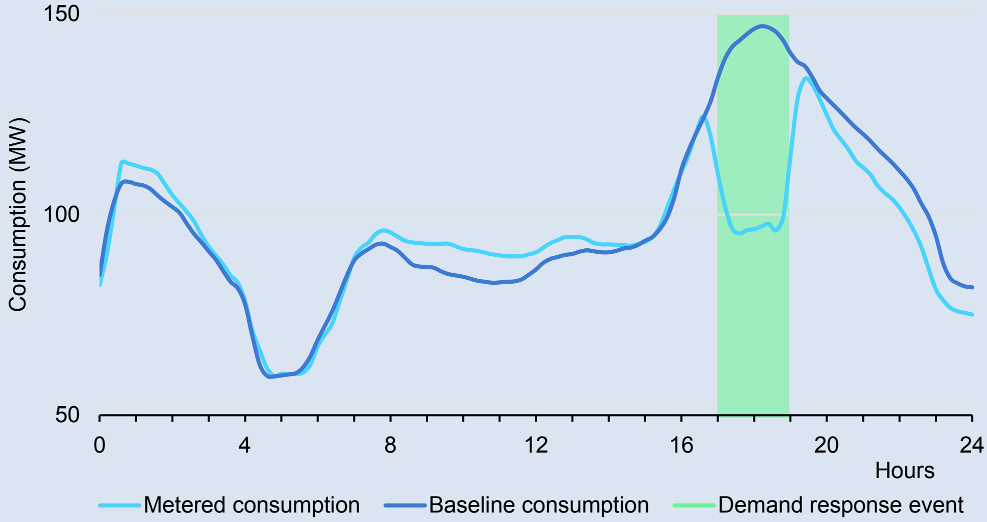
The Demand Flexibility Service (DFS) was launched by Great Britain's National Grid ESO (now the National Energy System Operator) in November 2022 in a context of risk and uncertainty for the power system for the winter 2022/2023. This programme rewards consumers, both households and commercial and industrial users equipped with smart meters, for shifting or reducing their electricity consumption during DFS events. It created a new source of flexibility activated by the system operator as an "enhanced action" between regular balancing actions and emergency actions.

During the winter 2022/2023, the service enlisted 1.6 million households and businesses, achieving 3.3 GWh in energy savings. The following winter, 2.6 million participants engaged in the programme, resulting in 3.7 GWh of savings. The maximum delivery during a demand response event peaked at 400 MW on 17 January 2024.

Energy or flexibility providers registered in the programme are responsible for alerting their consumers in advance of periods when they are incentivised to reduce or shift their demand, based on signals from the system operator. After the event, consumers receive financial compensation based on their actual response but are not penalised if they were not available. Apps are used to notify consumers about upcoming demand response events, offering advice on how to respond, and helping track energy and cost savings. Features like point rewards and messaging around the positive collective impact on the system, along with news coverage, have proved to boost consumers engagement.

Starting in winter 2024/2025, the design of the DFS will evolve towards an in-merit margin service, meaning it will be integrated into regular market operations based on economic dispatch rather than reserved for system stresses. Another evolution is the possibility of stacking revenues from both the DFS and the capacity market.

Consumption profile during a demand response event at peak time operated by National Grid ESO



Source: Reproduced from Octopus Energy (Data from the saving session organised on 12 December 2022).

A national surplus market supports the buildout of the national system of markets

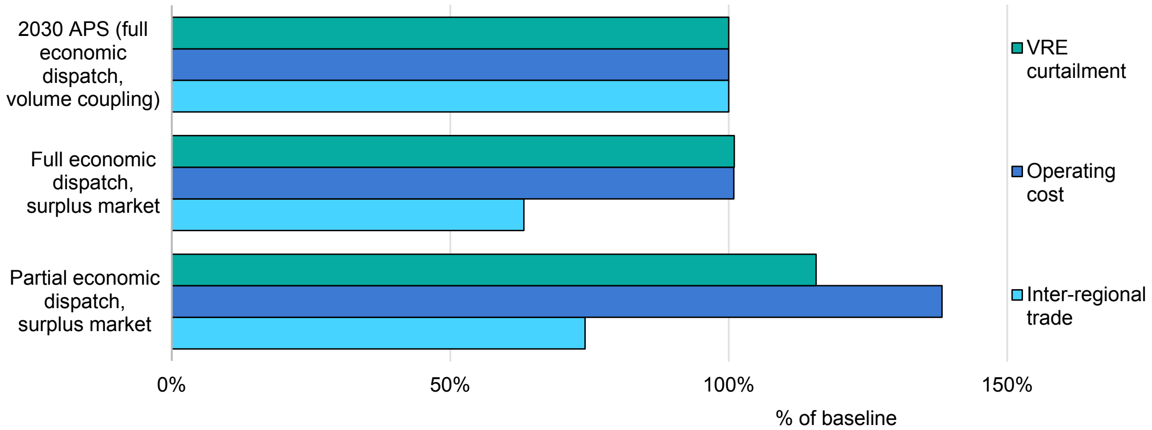
Inter-regional trade balances surplus and deficit over longer distances, capitalising on China's variety in geography, climatic conditions, distribution of demand and VRE generation potential to reduce generation costs. Previous IEA analysis in Building a Unified National Power Market System in China (April 2023) established the benefits in inter-regional coordination associated with progressing to a national market complementing the provincial or regional markets. As intermediary steps towards a more integrated national power market, two secondary market models were proposed to enhance regional co-ordination and resource sharing while preserving provincial autonomy in market design and dispatch decisions.

In a **surplus market**, only surplus generation, that is, electricity that exceeds the local demand after the initial dispatch in local markets, is traded between provinces or regions. Local markets retain significant autonomy in deploying and utilising their generation capacity. This model aims to increase renewable energy resource utilisation, particularly addressing curtailment issues.

The **volume-coupled market** model aims for a higher level of co-ordination by optimising the use of interconnections between provinces or regions. While local markets maintain control over pricing and dispatch, the national market determines the scheduled flows of interconnectors between provinces/regions based on the cleared volumes in the national day-ahead market. Local market operators then incorporate these interconnector flows as firm inputs in their dispatch decisions.

The current analysis confirms the benefits of a secondary market, finding that an inter-provincial surplus market could unlock a six-fold increase in the volume of electricity traded between regions in 2022, providing significant additional flexibility between provinces. Among the surplus market scenarios, those with partial economic dispatch exhibited more trade than those with full economic dispatch, indicating that a national surplus market can unlock significant benefits through inter-regional trade even while spot market implementation is still being finalised in the provinces. Progressing to fully volume-coupled markets could increase trade by a further 50-58%, reducing operating costs by around USD 13 billion in a system operated at partial fair dispatch, or USD 3 billion under economic dispatch.

Total inter-regional electricity trade, VRE curtailment and operating cost in scenarios with a surplus market compared to the Announced Pledges Scenario, 2030



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Economic dispatch remains the most effective way to unlock flexibility

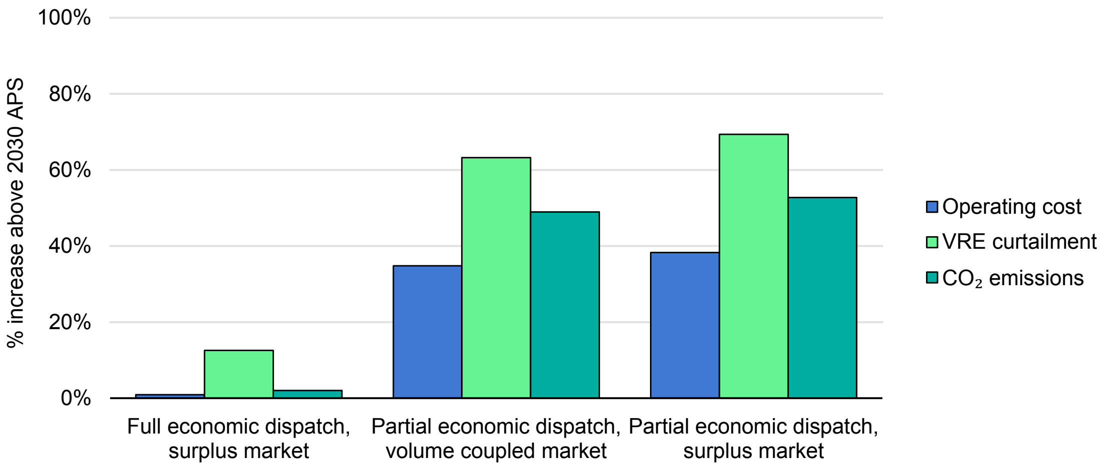
Implementing economic dispatch through spot markets brings the greatest benefits among the scenarios examined, reducing VRE curtailment by 60% when implemented in all regions (2030 APS), compared to partial implementation.

These benefits can be fully realised if the spot market design ensures proper price formation and provides accurate signals regarding energy availability or scarcity, thereby enhancing energy security. As the share of VRE grows, price volatility in short-term markets is likely to increase, sending important signals to stimulate investments in flexibility solutions that complement direct subsidy support. In turn, flexible assets help mitigate extreme price periods, benefiting both consumers and generators.

In the United States for instance, the price fluctuation in the real time spot market in some states can exceed USD 4 000/MWh in 2023 during peak demand episodes, and the average price gaps within the year varied between USD 25/MWh and USD 350/MWh depending on the state. In contrast, in China, where strict price caps apply, the average hourly price difference in 2023 ranged between RMB 120 and 630 (USD 17 and 88)/MWh in provincial spot markets, with the largest fluctuations observed in Inner Mongolia. In addition, negative prices are prohibited everywhere but in Shandong's spot market, which weakens the business case of flexible solutions such as storage and demand response. By comparison in South Australia, where VRE already accounts for 65% of the annual electricity generation, negative prices were experienced during more than 25% of hours in 2023 without compromising market functioning and they have become a key driver for battery investments.

Concerns about extreme price volatility and risk of "price cannibalisation" (where frequent low or negative prices can lead to further investment in VRE becoming economically unattractive) can be mitigated by targeted policies that protect consumers and support flexibility, such as long-term contracts for hedging and schemes encouraging storage deployment.

VRE curtailment, operating cost and CO_2 emissions in China compared to the Announced Pledges Scenario in 2030



Note: 2030 APS features both full economic dispatch and a volume-coupled national market.

Influence of carbon price on economic dispatch

In China, the carbon market for power plants is designed around a carbon intensity benchmark, which sets a standard for the amount of carbon emissions per unit of electricity generated. Plants emitting less than the benchmark generate surplus allowances, while those that emit more need to purchase allowances to cover their excess emissions.

This approach incentivises coal and gas power plants to improve efficiency but does not have a direct impact on the marginal cost of the electricity production, and therefore does not significantly alter the merit order curve where economic dispatch is implemented. Even if carbon prices significantly increase in China, the merit order position of thermal plants will remain largely unchanged. Only long-term, indirect effects can be expected, if plants strive to meet or exceed the benchmark, which could result in lower operational costs (improved technology or better fuel use).

Reforming the carbon market design will be crucial to introduce a direct cost per ton of CO_2 emitted, which would increase the marginal cost of electricity production for thermal plants. This can be done by transitioning from the current benchmark-based system to a cap-and-trade system similar to that of the EU, where a cap is set on total carbon emissions and companies can buy or sell allowances to emit. Such an evolution could be expected after 2030, based on the work plan published by the State Council in July 2024 announcing a shift from carbon intensity to total emissions control after China peaks its emissions.

In addition, the evolution of the dispatching system will also play a key role in determining the carbon emissions of the power fleet. In principle, as spot markets mature and steer dispatch, lower cost units are dispatched first, regardless of their carbon emissions. However, in China, state intervention can also mandate priority dispatch to some generators. For example, the fuel-switch action plan for coal power plants by 2027 published by the NDRC in July 2024 suggests that coal plants with the lowest emissions should be prioritised in the dispatch.

The path to flexibility through market reforms

As outlined, several critical barriers continue to limit China's ability to unlock full flexibility via power markets. Addressing these issues will require accelerating market reforms, refining regulatory frameworks and introducing market mechanisms that enable flexible resources to compete fairly. Lessons can be drawn from other jurisdictions which are also reforming their power markets to align with the evolution of power systems. Chapter 3 provides policy recommendations to guide this transition, focusing on creating a level playing field for flexible technologies, improving market coordination, and removing administrative and regulatory obstacles that hinder market-driven flexibility.

Case study: Electricity market reform in the European Union

The EU's electricity market design reform was initiated in response to the 2021-2022 global energy crisis, exacerbated by the Russian Federation's invasion of Ukraine in February 2022. Wholesale prices reached record highs primarily due to gas prices climbing, deeply affecting businesses and households exposed to market prices. In many European countries, wholesale power prices in the first half of 2022 were three to more than four times as high as the average in the first half of 2016 to 2021.

In this context, market functioning was questioned, and many voices called for measures to contain price volatility. Following a series of emergency measures taken by member states (MS), the EU Commission published a reform proposal in March 2023. Key market fundamentals, such as economic dispatch, were retained, acknowledging that they managed to send the correct price signals during energy scarcity, and to prompt significant energy savings. The final changes to the electricity market design rules, which came into force in July 2024, are relatively minimal. They focus on better protecting consumers, managing price variability for investors by improving long-term markets and facilitating the rapid deployment of renewables capacity. Markets monitoring was also reinforced.

Main measures adopted under the EU electricity market design reform

Better protect and empower consumers

- Right to fixed price contacts
- Hedging requirements on suppliers
- Protection from disconnection for vulnerable consumers
- Obligation for MS to designate a supplier of last resort
- Regulated retail prices can be applied in the event of a crisis for small consumers
- Right to participate in energy sharing schemes for self-consumption for all consumers
- Better and clearer contractual information
- Right for consumers to have multiple contracts from more than one supplier

Accelerate RE integration with flexibility services

- Periodic flexibility needs assessment by national regulatory authorities
- Support schemes made available for non-fossil flexibility capacity
- Indicative national target for demand response and storage by each MS
- Procurement of peak shaving product made available for TSOs during peak hours
- Operational costs accounted in network tariffs for system operators remuneration
- Better transparency from system operators on grid connection capacity and requests
- Creation of more trading opportunities (allowing cross-border intraday trading closer to real time; mandatory sharing of liquidity in the intraday market)

Reinforce long-term markets

- Promotion of PPAs
- Accessibility to instruments for default risk hedging
- Public support for new renewables and nuclear in the form of two-way CfDs
- Excess revenues from CfDs channeled to final consumers
- Liquidity boost to forward markets, through the creation of regional virtual hubs and long-term trading of financial transmission rights

Better monitor energy markets

- Adaptation of the scope of REMIT to current and evolving market circumstances
- Improved process for the collection of inside information and market transparency
- Enhanced supervision of reporting parties and data sharing
- Enhanced market transparency through an LNG price assessment and benchmark
- Harmonisation of fines set by regulatory authorities at national level
- Stronger role for ACER in investigations of significant cross-border REMIT cases

Notes: MS = member states. PPA = Power Purchase Agreement. CfD= Contract for Difference. REMIT = Regulation on wholesale energy market integrity and transparency. ACER= Agency for the Cooperation of Energy Regulators.

Source: IEA based on information from the European Commission.

Chapter 3. A policy toolkit for flexibility

Building on key insights: barriers to flexibility in China's power system

Drawing from the findings in Chapter 1 (flexibility needs and potential) and Chapter 2 (market-based solutions), this chapter first presents key recommendations that serve as a roadmap for potential implementation in the 15th Five-Year Plan (FYP) 2026-2030.

Key challenges identified in previous chapters include:

- **inadequate market design for flexibility,** leading to suboptimal resource allocation
- **barriers in electricity retail markets,** limiting consumer participation in flexibility markets
- **regional market fragmentation,** preventing efficient electricity sharing across provinces and regions.

This chapter responds to these challenges by proposing policy reforms at both national and provincial levels to ensure China's power system meets its flexibility needs efficiently, by maximising the role of low-carbon energy sources.

Policy toolkit for flexibility and key recommendations for the 15th Five-Year Plan

To meet its 2030 flexibility needs while aligning with its broader energy security and decarbonisation goals, China needs to implement policies to accelerate the implementation of markets at the national and sub-national levels. As identifying the right policies can be difficult, this comprehensive toolkit not only addresses flexibility needs but also supports national efforts towards carbon neutrality. It offers a set of recommendations and measures to harness the needed flexibility by 2030, making best use of market mechanisms and other regulations that China can deploy in this timeframe. This toolkit is complementary to policies that are beneficial to reduce the need for flexibility, such as energy efficiency or the deployment of advanced forecasting tools.

The policy actions are listed below according to the power markets or areas they affect directly. The recommendations aim to ensure that each market segment is reformed to support its core function (objective) and to minimise negative interferences with other segments.

Medium- to long-term markets

Long-term contracts play an important role as a hedging tool for consumers against price fluctuations, but they should not interfere with the efficient dispatching of resources. Reforms need to better connect medium- to long-term (MLT) markets with spot markets to ensure flexible resources can compete on an equal footing with conventional generators.

The need to connect MLT with spot markets applies to both intra-provincial and interprovincial trade, the latter currently only accessible to grid companies on the receiving end. The non-physical execution of MLT interprovincial contracts, as recently considered by the NEA, will avoid situations where the electricity flows from high- to low-prices zones, allowing the exporting province to fulfil its transmission plan by purchasing electricity from the receiving province during periods of surplus.

Key policies include:

- increasing the price range fluctuation (currently limited to +/-20% of the coal power benchmark price) of MLT contracts, and eventually removing range limitation
- increasing the timescale granularity of MLT contracts but promoting trading of standardised contracts through the power exchanges
- promoting the use of financial MLT contracts and lifting inflexibilities inherent in contract design (by removing obligations to adhere to a fixed curve for each time period, and instead agreeing on price and volume only)
- allowing for the non-physical execution of interprovincial contracts and authorising access of power generation companies and retailers to the interprovincial market
- reducing requirements for commercial and industrial consumers to procure 90% of their energy consumption through MLT contracts.

Spot markets

As spot markets have a significant impact on dispatch, their footprint and design are critical to ensuring efficient dispatching. Reforms need to continue and accelerate the rollout and enhancement of spot markets, further deploying them across the country and increasing participation of suppliers and consumers, to strengthen price signals and enable flexible operations. A strong price signal would effectively guide investments in flexibility resources such as storage.

Key policies include:

- increasing the price range fluctuation, allowing also negative prices to signal short-term flexibility needs
- maximising participation of players in the spot markets, by allowing new energy and smaller market players (through portfolio actors, such as aggregators and VPPs) to participate to spot transactions, allowing them to bid for both prices and volumes
- integrating interprovincial traded volume better into provincial market dispatch
- implementing closer-to-real-time trading (including intraday markets) and shorter settlement periods
- publishing real-time prices regularly on public platforms.

Ancillary services markets

Ancillary services markets can deliver significant revenue streams for flexibility providers, especially if they are able to contribute to several distinct services. This may be critical for conventional units gaining less revenue from selling energy over time. Reforms need to standardise and expand ancillary services markets to support power system flexibility and regional coordination.

Key policies include:

- unifying ancillary service markets and products across provinces and promoting trading of these products at the regional level, thereby incentivising deployment in all provinces
- implementing the market-based price mechanism for ancillary services in line with the national policy released in February 2024 and the Draft Basic Rules in October 2024
- removing barriers to participation of new energy, aggregators and VPPs, by for example increasing the range and granularity of the products (such as fast and slow reserves), allowing asymmetrical products for upward and downward flexibility, and bringing down thresholds for participation
- establishing mechanisms enabling the deployment of local, dedicated services where necessary (for example, the possibility to deploy local flexibility markets where distribution grids face a high level of congestion due to solar PV penetration).

Capacity markets

Reforms should support the transition to technology-neutral and performance-based capacity remuneration mechanisms to ensure fair competition between coal plants and emerging flexibility providers – like batteries and demand-side aggregators – and to minimise distortions of market prices.

Key policies include:

- reforming coal capacity payments and open capacity remuneration mechanisms to a broader range of flexible assets, like batteries and VPPs, with technology-neutral capacity payments, competitive bidding and remuneration based on performance
- introducing minimal flexibility requirements for all capacity payments. This flexibility can be further valued on the ancillary services markets
- introducing competitive auctions to select assets.

Retail markets

While large consumers can be given direct access to the wholesale markets to trade bulk electricity with large generators, retail markets play an important role to shield smaller consumers, such as households and other selected sectors, from wholesale price fluctuations. These consumers will continue to purchase electricity from retailers who manage the price risk on their behalf.

In the retail markets, reforms should aim to expand TOU tariffs and incentivise contracts linked to spot market prices to unlock demand-side flexibility. TOU tariffs can be updated periodically to reflect the evolution of the supply and demand situation, and can also be tailored for specific appliances like EV charging.

Key policies include:

- facilitating access of more large consumers to the wholesale market, including aggregators and VPPs
- increasing transparency and competition in the retail market, by enabling retailers to innovate in tariff packages that are reported transparently and are monitored by authorities
- increasing the TOU peak-to-valley ratio to encourage demand shifting and promote TOU for households
- promoting the adoption of more retail contracts linked to spot market prices for large consumers, and introduce higher premiums for customers seeking fixed price contracts
- incentivising power retailers to offer flexibility energy management and energy efficiency services to their consumers
- continuing the deployment of smart metering – especially TOU-capable meters – and promoting self-consumption in a system-friendly manner, with deployment of batteries to limit injection at times of excess renewables and limiting consumption at times of peak demand. Allow all customers equipped with solar panels and EVs to use their EVs to power their home appliances (vehicle-to-load) and the grid (vehicle-to-grid).

Grids

Reforms should modify the remuneration model for grid companies to reward flexibility and better grid management.

Key policies include:

- reforming interconnector payments to reward capacity availability rather than utilisation rates (which currently incentivise pairing VRE with coal plants)
- improving grid transparency for renewable energy projects and future grid capacity expectations
- implementing time-varying network charges to further encourage demand shifting away from times of (net) peak load and higher grid congestions.

National planning and market unification

As China moves towards a national power market system, regional integration will likely be a key focus of the 15th FYP (2026-2030), ensuring that provinces can trade surplus energy efficiently, thus making use of VRE-rich areas and increasing system-wide flexibility.

Planning needs to be articulated around markets. In a market-based system, planning provides the framework under which markets operate and takes as essential inputs national policy objectives and existing market designs. In contrast, administrative planning may result in suboptimal investments and overcapacity, requiring administrative corrections such as capacity payments to coal plants. Reforms should continue towards the integration of national and provincial markets to optimise trade and ensure efficient balancing across regions. These reforms may also support reducing the complexity of the current multi-layered structure of the Chinese market.

Key policies include:

- developing scenarios and planning tools at the national and provincial levels to support the investigation of flexibility needs and testing the impact of new policy measures
- mandating explicit flexibility assessments in the national and provincial planning processes
- softening administrative measures, for example, storage mandates for wind and solar plants and minimum utilisation rates for VRE, as market reforms are implemented
- further harmonising grid connection rules and ensuring compliance with those rules
- establishing flexible connections and predictable curtailment frameworks to ensure efficient use of renewables and maintain investment attractiveness.

A policy toolkit for the 15th Five-Year Plan to unlock flexibility through power markets

	Maximise flexibility potential	Boost deployment of new flexible resources	Optimise resource sharing nationwide
MLT markets	Increase temporal granularity of physical contracts; Increase price range fluctuation	Lift inflexibilities in contract design; Promote the use of financial contracts	Open interprovincial trade to market participants, besides grid companies
Spot markets	Trade closer to real time and shorten settlement periods; Advance economic dispatch	Maximise participation; Remove barriers to new energy and VPPs	Better connect interprovincial and provincial spot markets
Ancillary services markets	Deploy mechanisms for dedicated services where necessary; Implement market-based price mechanisms		Unify markets and products nationwide; Promote interprovincial trading of reserves
Capacity markets	Introduce minimum flexibility requirements; Remunerate based on performance	Select assets competitively	
Retail markets	Incentivise contracts linked to spot market prices for large consumers; Promote TOU for households	Increase TOU peak-to-valley ratio; Deploy smart metering and promote system-friendly self-consumption	
Grids	Implement time-varying network charges	Improve transparency of grid availability for future projects	Remunerate grid capacity instead of usage rate; Harmonise grid connection rules, promote flexible connections and predictable curtailment frameworks
Planning and market unification	Mandate flexibility assessments in planning and develop tools to support this exercise	Articulate planning around markets and soften administrative measures as markets are implemented	Advance national and provincial markets integration

Step by step guide for toolkit implementation

The policy toolkit should be applied through the following steps to ensure effective and tailored flexibility improvements across provinces and the national system.

Step 1: Conduct flexibility needs assessment and assign responsibilities

Each province and region should start with a comprehensive flexibility needs assessment to identify local requirements based on resource availability, grid conditions and projected supply-demand evolution. These provincial assessments cannot be isolated; they must account for the benefits of interprovincial connections and contributions to the national system.

Responsibilities can be allocated as follows among stakeholders:

- **National authorities** set the standards for conducting assessments and ensuring alignment with national targets. In particular, the contribution of interconnections to local flexibility can be harmonised across provinces and regions. The time horizons for the assessment need to be defined, not limited to the near future. Requirements need to ensure that the assessments address all flexibility timescales and include normal operating conditions as well as stress tests. Mandating that a minimum share of flexibility is to be delivered from low-carbon sources can support national climate and energy targets.
- **Provincial and regional planners** carry out annual flexibility assessments based on local grid conditions and resource availability, and report whether flexibility sources are sufficient to meet the needs. Over time, these provincial/regional assessments could be coordinated or even centralised.
- **Grid operators** conduct technical evaluations of the grid's capacity to handle fluctuations in supply and demand.
- **Market operators** deploy markets and ensure conditions are met to integrate and efficiently dispatch flexibility sources.

This step ensures that each province or region has a clear understanding of its flexibility needs and lays the groundwork for subsequent measures.

Flexibility needs assessment in other power systems

Maximising the use of available flexibility in the system is a common challenge for systems across the world.

In the United States, MISO (the Midcontinent Independent System Operator) has been conducting a periodic Regional Resource Assessment since 2021, which includes a flexibility assessment 10 and 20 years ahead. This analysis aims at studying the evolution of the net load curve, identifying whether MISO's reserves are sufficient for future needs and periods of potential gaps. Similarly, CAISO (the California Independent System Operator) performs an annual flexible capacity needs assessment for up to three years in the future. The results of this study are then used to allocate shares of the flexible capacity needs to load-serving entities.

In the European Union, the new regulation amending the electricity market design, which entered into force in July 2024, now requires each of the member states (MS) to conduct a periodic assessment of their flexibility needs. This exercise should be done by the respective national regulatory authority, based on inputs from system operators and a common European methodology due to be released in 2025. Based on this assessment, MS need to define an indicative target for non-fossil flexibility and include it in their National Energy and Climate Plans.

Step 2: Prioritise and tailor policy measures based on provincial or regional context

Following the flexibility assessment, each province or region should prioritise and select specific policy measures for which they hold authority and that align with their local context. In the first instance, provinces can be categorised by the level of VRE penetration and whether the spot market is mature or at early stages.

Provinces with high VRE penetration (e.g., Gansu and Qinghai) should focus on introducing ramping products and integrating a wider range of energy resources to address variability. Provinces with low VRE penetration (e.g. Anhui and Guangdong) can prioritise efficient use of conventional resources and prepare the market for higher VRE integration in the future.

In provinces where spot markets are operational, the priority should be to ensure that market design maximises the use of VRE and incentivises flexibility. Where power markets are still nascent, efforts should focus on revising or developing new rules and market mechanisms conducive to flexibility, developing pilot programmes to meet local flexibility needs and investing in capacity building and knowledge sharing to facilitate the deployment of markets.

Area classification based on selected characteristics

High VRE penetration		
Mature spot market	**Early stage/no spot market**	
Liaoning Gansu Shanxi Western Inner Mongolia Hebei Henan	Guangxi Hunan Jiangxi	Heilongjiang Jilin Ningxia Qinghai Xinjiang

Low VRE penetration			
Mature spot market		**Early stage/no spot market**	
Anhui Fujian Guangdong Hubei Jiangsu	Shandong Shaanxi Sichuan Zhejiang	Beijing Chongqing Guizhou Hainan	Shanghai Tianjin Tibet Yunnan

Notes: In this classification, an area with a VRE share of 10% or above in its generation mix in 2022 is classified under “high-VRE penetration”; a spot market having achieved at least long-term trial operation is classified “mature”. Yunnan, Guizhou, Guangxi and Hainan have been directly integrated into the Southern Regional Spot Market Trial, which is at an early stage of development.

Step 3: Implement tailored policies and integrate market improvements

Once the priority measures are selected, a coordinated implementation of reforms across the various market segments and grid operations should be ensured at the local level (province or region). This step ensures that market design is fully aligned with the flexibility needs identified in Step 1.

Key areas for implementation include MLT markets, spot markets, ancillary services, retail markets, grids and planning.

China’s experimentation with power markets has followed a well-defined, phased approach, beginning at the provincial level. This method enables gradual reform, controlling risks and refining mechanisms before scaling to the national level. As detailed in Chapter 2, the development of spot markets and other market reforms typically progresses through phases of simulation, pilot trials and ultimately continuous operation with financial settlements linked to market outcomes. Implementation of these new reforms could continue to embrace this approach, allowing markets to evolve incrementally but effectively.

Local application of the policy toolkit according to area characteristics

Priority measures (by type of market or segment)	Area characteristics			
	High VRE		Low VRE	
	Mature spot market	Early/no spot market	Mature spot market	Early/no spot market
Medium- to long-term (MLT) markets				
Increase price range fluctuation	●	●	●	●
Increase granularity of (physical) MLT contracts	●	●	●	●
Promote the use of financial MLT contracts	●		●	
Lift inflexibilities inherent in contract design	●	●	●	●
Reduce requirements for C&I consumers to procure 90% of their energy consumption through MLT contracts	●	●	●	●
Spot markets				
Advance economic dispatch implementation		●		●
Maximise participation	●		●	
Increase price range fluctuation and allow negative prices	●		●	
Deploy intraday trading if not in place	●		●	
Shorten settlement period	●			
Adjust TOU tariffs according to spot market prices	●			
Allow price and volume bidding for renewables into the spot market	●		●	
Include interprovincial trade into local spot market clearing	●		●	
Publish real-time price on public platforms	●		●	
Ancillary services				
Unify products nationwide	●	●	●	●
Implement market-based price mechanisms	●	●	●	●
Remove barriers to participation of new energy, aggregators and VPPs	●	●	●	●
Develop local, dedicated services where necessary	●	●		
Capacity market and subsidies				
Open capacity remuneration mechanisms to a broader range of flexible assets with a competitive selection process	●	●	●	●
Introduce minimal flexibility requirements for all capacity payments	●	●		
Remunerate capacity based on system-friendly performance at critical times	●	●	●	●

Priority measures (by type of market or segment)	Area characteristics			
	High VRE		Low VRE	
	Mature spot market	Early/no spot market	Mature spot market	Early/no spot market
Demand side				
Remove barriers for large consumers access to the wholesale markets	●	●	●	●
Solicit demand response from C&I consumers	●	●	●	●
Solicit residential demand response	●	●		
Set up frameworks for aggregation and dynamic pricing	●			
Encourage local consumption at hours of high VRE production through tariffs and deployment of integrated projects (load + storage + VRE)	●	●	●	●
Retail markets				
Increase TOU peak-to-valley ratio	●	●	●	●
Enable retailers to innovate in tariff packages, and promote the adoption of more retail contracts linked to spot market prices for large consumers	●		●	
Implement tariffs promoting self-consumption and grid-friendly injection	●	●		
Grids				
Implement time-varying network charges	●	●		
Improve grid transparency for renewable energy projects and future grid capacity expectations	●	●	●	●
Planning and operations				
Develop scenarios and planning tools to support investigation of flexibility needs	●	●	●	●
Mandate explicit flexibility assessments in the provincial planning process	●	●	●	●
Soften storage requirements for new energy	●		●	
Encourage market-based revenue stacking to enhance the storage business model	●		●	
Establish predictable curtailment framework	●		●	
Invest in capacity building to learn from other jurisdictions with advanced power markets		●		●

Step 4: Monitor and adjust policies based on performance

After implementing policies, it is crucial to establish monitoring frameworks to track the effectiveness of the reforms and adapt them as necessary.

Key performance indicators should include metrics like VRE integration levels, storage utilisation rates, spot market participation rates and demand-side response engagement.

Annual reviews should be conducted to assess progress, with the flexibility assessments updated regularly.

Based on performance data and evolving market conditions, policies can be adjusted to optimise flexibility and ensure long-term efficiency.

Case study: Policy prioritisation for unlocking flexibility in Guangdong

Guangdong is one of China's most economically developed provinces and serves as a key driver of the country's industrial growth. The province has a low share of renewable energy in its electricity mix, with coal still dominating generation, accounting for 73.6% of total electricity in 2023. As of 2023, VRE penetration (wind and solar PV) reached only 5.9%. However, Guangdong has been a pioneer in electricity market reforms, piloting one of China's first spot markets since 2017 (and which became operational in December 2023) and having a well-developed retail and ancillary services market.

The province faces growing electricity demand with sharper peaks in summer when air conditioner consumption peaks. The maximum peak load hit a record of 145 GW in 2023, 3 GW higher than in 2022. Managing these changes in the load profile, along with increasing shares of renewable energy, will require Guangdong to focus on enhancing flexibility in its power system through market reforms and better management of distributed resources.

Given the characteristics of Guangdong – **low VRE penetration** and an **operational spot market** – the following policies should be prioritised to enhance flexibility and increase integration of renewables in the future, while managing its increasing demand:

- enhancing the design of MLT contracts, by increasing timescale granularity and allowing for more flexible conditions that can adjust pricing based on market conditions. Guangdong's electricity market is largely dominated by bilateral MLT contracts, representing 89% of the total traded volume in 2023.
- increasing spot market participation by including more small market players, such as distributed energy resources (DER) and storage, through VPPs.

Although the Guangdong spot market allows both supply and demand-side entities to participate, barriers to entry remain for the smaller market players.

- unifying ancillary services markets across the Southern Grid Region and promoting cross-provincial trading of reserves and frequency regulation services. Guangdong has already integrated the peak shaving ancillary market with its spot market and commenced regional frequency trading. It established a cross-provincial reserve market in 2022. Further unification across the region will help maximise flexibility by enabling cross-provincial resources sharing, critical for addressing peak demand.
- expanding market-based demand-response programmes, targeting industrial and large commercial consumers. Guangdong's demand response initiatives have already shown promise, with over 6 GW of peak-shaving cumulative capacity reported by users in 2022. Increasing participation and allowing continuous operation (rather than invitation-based) will provide Guangdong with cost-effective flexibility solutions.
- expanding Time-of-Use (TOU) tariffs and promoting dynamic pricing linked to the spot market, especially for industrial users. Guangdong's retail market is well-developed but lacks the flexibility needed to incentivise significant demand-side response. Updating TOU tariffs to better reflect real-time conditions and encouraging market-based retail contracts will unlock more flexibility.

The path forward

In summary, the proposed policy toolkit focuses on the development of markets and regulations to incentivise flexibility, enhancing regional co-ordination and articulating long-term planning around markets. The policy toolkit is pivotal for enabling China to achieve a flexible, efficient power system by 2030. The implementation of these new reforms can embrace the approach taken by China in earlier market reforms to control risks, experimenting with pilot trials at the provincial level to refine mechanisms before scaling to the national level. Aligning the 15th Five-Year Plan with broader goals of energy security and decarbonisation will ensure that China remains on track to meet its carbon neutrality targets while addressing the immediate and growing need for system flexibility.

To ensure the continued success of power sector reforms, China may also need to address building a robust governance framework, increasing institutional capacity and advancing its commitment to ambitious reforms. Critical steps include establishing sound legal structures, promoting data transparency, enhancing regulatory capacity to monitor and oversee markets, and articulating a clear, long-term strategy for the power sector. These reforms will be essential in supporting the efficient, secure and sustainable transformation needed to meet the demands of an increasingly renewable-powered grid.

The ultimate success of this transformation hinges on the capacity of the institutions, as well as a firm commitment to ambitious policy measures that enable the full scope of power markets while unlocking the flexibility potential from energy storage, distributed energy resources and demand-side participation. These policies will ensure that China is not only capable of balancing its system in real time, but also of leading the global energy transition.

Annex

Modelling methodology

To examine power system flexibility in China, a techno-economic analysis was carried out using the IEA's Regional Power System Model for the Announced Pledges Scenario (APS) of the World Energy Outlook (WEO) 2023. The analysis focuses on a one-year "snapshot" in 2030 to reflect the benefits of power system reforms that can be realised in the 15th Five-Year Plan (2026-2030). The national results for supply and demand come from the IEA's Global Energy and Climate model (GECM) and are disaggregated into eight regions with regional transmission interconnection among them. Different cases are studied to explore the impact of varying levels of market implementation, as well as co-ordination and trade among the regions. Dispatch incorporating different levels of administrative allocation of full load hours (FLHs) and economic dispatch is also explored to highlight the interplay between China's move towards more economic dispatch and the role of a national market.

The APS is in line with China's announced pledges and targets for emissions reduction, in particular with the dual carbon goals (peaking carbon dioxide emissions before 2030 and reaching carbon neutrality before 2060). However, it deviates from existing pledges in some aspects, reflecting the fact that China's strong VRE capacity growth has meant that it achieved its 2030 VRE capacity targets well ahead of schedule. Hence, there is room for further ambition.

Regional set-up and transmission capacity

The model includes eight nodes corresponding with China's major grid regions. Compared to the previous IEA report in 2023, dedicated to the construction of a national power market in China, the separation of Yunnan province as its own region allows better alignment of the regions with the different climate zones in China. Including Tibet in the Southwest Region better reflects its role in the regional power system, its connections with other provinces and the regional power balance than grouping it with the Northwest Region.

Division of the eight modelling regions

Modelling region	Abbreviation	Provinces and autonomous regions
Northwest	NWR	Gansu, Shaanxi, Ningxia, Xinjiang, Qinghai
North Central	NCR	Beijing, Hebei, Inner Mongolia, Shanxi, Tianjin, Shandong
Northeast	NER	Heilongjiang, Jilin, Liaoning
Central	CR	Henan, Hubei, Jiangxi, Hunan
Eastern	ER	Anhui, Jiangsu, Shanghai, Fujian, Zhejiang
South	SR	Guangxi, Guizhou, Hainan, Guangdong
Southwest	SWR	Tibet, Chongqing, Sichuan
Yunnan	YR	Yunnan

Note: Considering the availability of data and clarity in presenting the modelling, Inner Mongolia is not subdivided into eastern and western parts but is attributed entirely to NCR.

Transmission capacity between the regions is based on existing AC and DC transfer capacity, combined with the 78 GW planned transmission expansion from 2022 levels expected to be complete by 2030. This may be somewhat conservative as it includes projects from the 14th Five-Year Plan but not the 15th Five-Year Plan, which was not public at the time of publication. However, given the timescales required to construct and commission new transmission lines, the full capacity increase announced for the 15th Five-Year Plan period is unlikely to be completely operational by 2030.

Inter-regional transmission capacity (GW) assumed for 2030

		Receiving region							
		CR	**ER**	**NCR**	**NER**	**NWR**	**SR**	**SWR**	**YR**
Sending region	**CR**	-	10	6	-	1	3	5	-
	ER	-	-	-	-	-	2	-	-
	NCR	6	18	-	3	15	-	-	-
	NER	-	-	13	-	-	-	-	-
	NWR	49	36	27	-	-	-	12	-
	SR	-	2	-	-	-	-	-	3
	SWR	21	38	-	-	4	10	-	-
	YR	-	-	-	-	-	39	-	-

Note: Values are shown rounded to the nearest integer. The exiting transmission capacity comes from the National Electric Power Reliability Annual Report (2022) by the National Energy Administration (NEA) and China Electricity Council (CEC), and it is assumed that all new planned "3 AC 9 DC" transmission lines in the 14th Five-Year Plan from Commissioning of Research and Demonstration on Supporting Hydropower, Wind, Solar, and Regulatory Power Sources for Transmission Corridors in the 14th Five-Year Plan by the NEA will be in operation by the end of 2030.

Electricity demand

Annual electricity demand projections and hourly load profiles for each end-use sector are based on detailed bottom-up analysis from the WEO 2023, which estimates hourly demand by end use for the residential, services, agricultural, industrial and transport sectors. The projections rely on national macro indicators – for example, population dynamics and economic growth – integrating the latest policies. The disaggregation of the load into the eight modelling regions is based on regional projections considering key drivers of each end use and factoring in regional trends, policies and other conditions. The hourly potential for demand-side response by region is based on the projected demand by end use in each region.

Generation and storage capacity

Power generation and storage capacity in the APS is determined on the basis of the projected evolution of the existing fleet in line with announced pledges and targets for emissions reduction. These capacities are disaggregated to regional level and are pre-determined, static inputs. The model assumes that projected capacity for existing and new technologies is made available for dispatch. For the regional distribution, both existing plans and the expected evolution of capacity in each region are taken into account, including considerations about maintaining regional security of supply. For the deployment of coal plants, a particular role is played by co-generation plants following the changing heat demand resulting from the shift of heavy industry towards the northern regions, and in particular towards the Northwest. Co-generation plants are broadly divided into industrial steam and district heating operations, and a seasonal pattern was applied to the district heating plants. Gas-fired plants are developed in each region as per the evolution of the gas supply infrastructure. New nuclear reactors are deployed in accordance with planned and proposed sites.

The hourly modelling includes detailed operating characteristics, for example, operating costs, plant technical minimum operating levels, minimum up and down times, start-up times and ramp rates. Fuel prices were derived from the WEO 2023; for steam coal prices, the price differences between the regions were estimated considering current market trends and transport costs.

Renewable generation profiles

Wind (on- and offshore) and solar PV (utility-scale and rooftop PV) capacity are allocated on the basis of over 4 000 representative sites in accordance with resource potentials; population density; distance from power grids; exclusions based on land use, altitude or slope; and policies in place. Hourly wind and solar generation were simulated from the selected wind and solar sites across China. Hydro capacity was broken down in each region into four main types: run-of-river, run-of-river with small storage, reservoir and pumped hydro storage. Different types of seasonal inflow were considered for each of these types. The expansion of the remaining renewables technologies (bioenergy, concentrating solar power, geothermal and marine) was based on resources and capacity requirements across the different regions.

Representing levels of regional co-ordination

Two main cases of inter-regional co-ordination were investigated to compare differing levels of co-ordination between the eight regions. A low-co-ordination case was used to represent the APS in 2022 only, based on historic data. The eight-node configuration of the model means that co-ordination within regions is effectively assumed and thus the results give only a conservative estimate of the full benefit of progressing towards a nationally integrated approach.

Case	Inter-regional co-ordination
Low co-ordination	Transmission capacity and limited flows between regions, based on historic levels.
Surplus market	Unit commitment set within each of the eight modelling regions independently, dispatch then allowed to adjust within the stable operating limits of all generators to enable trade between regions according to inter-regional transmission capacity.
Volume coupled market	Nationally integrated dispatch with flows optimised across the entire system.

Representing dispatching practices

Spot market development is represented through dispatch practice within the regions. The partial economic dispatch case is intended to broadly reflect the current dispatch practices expected, based on the rules and maturity of the provincial spot market pilots. These trials still allow for some generation types to be taken as firm inputs to the dispatch. However, as these are typically first in the merit order (wind, solar, hydropower, nuclear) or are present in very low shares (gas), the dispatch could nonetheless be expected to come very close to a full economic optimisation.

Case	Dispatch practice
Historical FLH allocations	Thermal generators constrained to minimum FLH in keeping with historical dispatch levels for all regions
Partial economic dispatch	Thermal generators constrained to minimum FLH in Northwest, North Central, Northeast, Northwest, East and Southwest regions and full economic dispatch in the Central, South and Yunnan regions
Full economic dispatch	All dispatch determined on a least-cost basis without constraints on the operating hours for any generation

Representing demand and non-energy market participation

Access to non-energy markets represents an important additional source of revenue for assets. Several cases are used to represent varying levels of demand-side flexibility, being a key component of power system flexibility given China's significant demand growth. These explore additional demand-side participation beyond the existing "orderly consumption" peak-shaving mechanism and separate demand into sectors consistent with the APS sectors, outlined in the *Electricity demand* section. As this publication has a greater focus on flexibility compared to the 2023 report, a more detailed investigation was carried out of the participation of demand-side aggregation in various sectors, as well as of participation in ancillary service markets.

Case	Market participation
Access to ancillary service markets	Assets can access ancillary service markets to provide services such as regulating reserve and spinning reserve
Demand-sector shifting	The load of the stated demand sector can be shifted to the extent consistent with the 2030 APS levels
No demand-sector shifting	The load of the stated demand sector has a fixed profile and cannot be shifted
Low demand-sector shifting	The load of the stated demand sector can be shifted to a reduced extent below the 2030 APS levels

Scenarios investigating different levels of power system flexibility

	2022	Partial ED, volume coupled market	Partial ED, inter-regional surplus market	Low AS market participation	Inter-regional surplus market	Low Commercial & Industrial shifting	No Commercial & Industrial shifting	Low EV & Residential shifting	No EV & Residential shifting	**2030 APS (full ED, volume coupled market)**	Full AS market parti-cipation
Industrial demand shifting	Limited	Yes	Yes	Yes	Yes	Reduced	No	Yes	Yes	Yes	Yes
Commercial demand shifting	No	Yes	Yes	Yes	Yes	Reduced	No	Yes	Yes	Yes	Yes
Residential demand shifting	No	Yes	Yes	Yes	Yes	Yes	Yes	Reduced	No	Yes	Yes
Agriculture demand shifting	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Passenger EV demand shifting	No	Yes	Yes	Yes	Yes	Yes	Yes	Reduced	No	Yes	Yes
Other transport demand shifting	No	Yes	Yes	Yes	Yes	Yes	Yes	Reduced	No	Yes	Yes
Demand AS participation	No	No	No	No	No	No	No	No	No	No	Yes
Storage BtM charging	No	VRE Only	VRE Only	VRE Only	VRE Only	VRE Only	VRE Only	VRE Only	VRE Only	VRE Only	VRE Only
Storage FtM access to AS markets	No	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Dispatch	Fair Dispatch all regions	FD some regions	FD some regions	ED with constraints	ED with constraints	ED with constraints	ED with constraints	ED with constraints	ED with constraints	ED with constraints	ED with constraints
Interregional coordination /trade	Historic flows	Volume coupled market	Surplus Market	Volume coupled market	Surplus Market	Volume coupled market	Volume coupled market	Volume coupled market	Volume coupled market	Volume coupled market	Volume coupled market

Notes: ED= economic dispatch. FD= fair dispatch (plants are allocated a number of full-load hours over the year). BtM = behind-the-meter. FtM = front-of-the-meter. TOU= time-of-use tariffs. "Surplus market" refers to a situation where local markets with different designs co-exist while the whole interconnection is supported by a national market where excess generation is traded on a voluntary basis. "Volume-coupled market" refers to a situation where interconnection flows are optimised compared to the surplus market, while keeping local autonomy in price formation and dispatch (no price coupling).

Abbreviations and acronyms

ACER	Agency for the Cooperation of Energy Regulators
APS	Announced Pledges Scenario
BTM	behind-the-meter
C&I	commercial and industrial
CCS	carbon capture and storage
CEC	China Electricity Council
CETO	China Energy Transition Outlook
CfD	contract for difference
CO_2	carbon dioxide
CRM	capacity remuneration mechanism
CSG	China Southern Power Grid
ED	economic dispatch
EPPEI	China Electric Power Planning and Engineering Institute
ETS	emissions trading scheme
FD	fair dispatch
FLH	full load hours
FTM	front-of-the-meter
FYP	Five-Year Plan
HVDC	high-voltage direct current
IEA	International Energy Agency
IT	information technology
MCP	market-clearing price
MLT	medium- to long-term
NDRC	National Development and Reform Commission
NEA	National Energy Administration
NEMOs	Nominated Electricity Market Operators
PPA	power purchase agreement
PV	photovoltaic
REMIT	Regulation on Wholesale Energy Market Integrity and Transparency
RMB	Renminbi (Chinese Yuan)
SASAC	State-owned Assets Supervision and Administration Commission
SGCC	State Grid Corporation of China
TOU	time-of-use
UHV	ultra-high voltage
VPP	virtual power plant
VRE	variable renewable energy
WEO	World Energy Outlook

Units of measurement

GW	gigawatt
GWh	gigawatt-hour
kWh	kilowatt-hour
kvar	kilovolt-ampere reactive
MW	megawatt
MWh	megawatt-hour
TWh	terawatt-hour

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