2026 China Power Market Outlook: 10 Key Trends for Market Players

2026.7

Authors and Acknowledgments

Authors

Zihao Chen

Shuo Gao

Yi Jiang

Ting Li

Yujing Liu

Ziyi Liu

Jialin Tian

Liyue Zhang

Authors listed alphabetically. All authors from RMI unless otherwise noted.

Contacts

Shuo Gao, sgao@rmi.org

Copyrights and Citation

Shuo Gao, et al., *2026 China Power Market Outlook: 10 Key Trends for Market Players*, RMI, 2026,

https://rmi.org/resources/2026-china-power-market-outlook/.

RMI values collaboration and aims to accelerate the energy transition through sharing knowledge and insights. We therefore allow interested parties to reference, share, and cite our work through the Creative Commons CC BY-SA 4.0 license. **https://creativecommons.org/licenses/by-sa/4.0/**.
All images used are from iStock.com unless otherwise noted.

About RMI

Rocky Mountain Institute (RMI) is an independent, nonpartisan nonprofit founded in 1982 that transforms global energy systems through market-driven solutions to secure a prosperous, resilient, clean energy future for all. In collaboration with businesses, policymakers, funders, communities, and other partners, RMI drives investment to scale clean energy solutions, reduce energy waste, and boost access to affordable clean energy in ways that enhance security, strengthen the economy, and improve people's livelihoods. RMI is active in over 50 countries.

Table of Contents

Executive Summary 7

1. Provincial power spot markets now cover nearly all provinces, with spot prices emerging as the pricing anchor for medium- to long-term power and retail markets 10

Average spot prices continue to fall, and regional differentiation is becoming more pronounced 10

Spot prices are strengthening time-of-use price signals and enabling more granular transactions in medium- to long-term and retail markets 13

2. Time-segmented M2L trading has become widespread, with intraday price differentials constrained by trading price limits in some regions 14

Time-segmented M2L transactions have become widespread, and the transaction price is gradually decoupling from administrative time-of-use (TOU) pricing 14

For time-segmented trading, the price limit for long-term cycles is set at the coal power benchmark price ±20%, while for short-term cycles it closely follows the spot market limit. 15

Due to trading price limits, intraday peak-to-valley price fluctuations in M2L time-segmented transactions are limited in certain regions........ 15

3. Wholesale-retail price pass-through strengthens, and retail-side use of market-based TOU electricity pricing accelerates 17

Retail packages align more closely with the wholesale market, better reflecting the average wholesale market price 17

Retail TOU pricing is gradually transitioning to a market-based model, but progress differs by region........ 18

Regions adopt measures to mitigate electricity price risk to users 20

4. **Mechanism pricing has been implemented nationwide, with notable disparities emerging in regional implementation plans, bidding outcomes, and settlement expenses across regions 23**

All regions nationwide have rolled out bidding for renewable mechanism pricing, with significant differences in bidding plans and results 23

Nationwide, industrial and commercial power users are paying widely different rates under mechanism pricing 27

5. **The capacity pricing mechanism is expanding to include more types of generation-side entities, with the compensation depending on peak-serving capability 29**

Under a unified national framework, the differences in details regarding capacity calculation, unit price calculation, and performance assessment across different provinces will affect the actual capacity revenue level of operating entities 30

Capacity revenue accounts for a growing share of generation revenue, while newer mechanisms increasingly reward peak-serving capability 33

6. **Capacity-based transmission and distribution tariffs represent a significant policy development, while system operation fees play a growing role in the overall electricity price structure 34**

A capacity-based transmission and distribution tariffs model is established to promote local renewable energy consumption 34

Renewable mechanism pricing and generation-side capacity pricing drive system operation fee adjustments and reshape end-user electricity cost structures 35

7. Stand-alone energy storage economics improve as capacity pricing rolls out, while market-based TOU pricing reshapes industrial and commercial storage operations 41

National policy establishes capacity pricing mechanisms for stand-alone energy storage, with compensation tilted toward longer-duration projects 41

Market-based TOU price formation is reshaping industrial and commercial storage operations, making diversified revenue models a key transition pathway 44

8. Generation-type virtual power plants are becoming a key route for distributed renewables to enter power markets 47

Distributed renewables are required to trade through spot markets, and aggregation through generation-type VPPs offers greater arbitrage potential 47

Distributed renewables aggregators are expected to transition into generation-type VPPs in some provinces 49

9. Green power supply-demand balance remains relatively loose, while application scenarios are expanding, driving demand for green energy certificates.... 51

Green power trading rules continue to evolve; green power supply is expected to remain ample over the next two years 52

Green energy certificate life-cycle management is improving, with its applications expanding across a broader range of use cases. 54

10. Vehicle-to-grid pilots continue to expand, and provinces begin introducing discharge pricing mechanisms 57

V2G pilots are concentrated in regions with high EV penetration 57

Three provinces introduce V2G discharge pricing policies; revenues depend on access to peak-price hours 59

Endnotes 62

Executive Summary

China has advanced power market reform and the development of a unified national power market system to support the New Power System, improve resource allocation, and maintain electricity system reliability. In 2025, China reached an important milestone: the unified national power market system was preliminarily established, with significant progress in both policy design and market practice. These developments are contributing to changes in market and pricing arrangements associated with the New Power System and the New Energy System.

Provincial spot markets now cover nearly all provinces. Spot markets that are either formally operating or under continuous trial operation cover 29 provincial-level power grids and are playing an increasingly important role in price discovery and real-time supply-demand balancing.[i]

The *Basic Rules for the Medium- to Long-Term (M2L) Power Market* have been updated to reflect new market needs. The revised rules introduce regular transactions between the State Grid and China Southern Power Grid regions, further supporting interprovincial and interregional power flows. Time-of-use (TOU) price formation is guided to shift from administrative determination toward market-based formation: market-participating users will follow the TOU periods and prices set in contracts rather than those uniformly set by local regulators. At the same time, M2L transaction cycles are expanding in both directions, with shorter-cycle products improving coordination with spot markets and longer-cycle products supporting multiyear renewable energy trading.

Mechanism pricing for renewable energy has been implemented across regions, marking the full transition of renewable on-grid electricity from regulated pricing to market-based participation. The *Notice on Deepening the Market-Oriented Reform of Renewable Electricity Prices and Promoting the High-Quality Development of Renewables*, issued by the National Development and Reform Commission (NDRC) and the National Energy Administration (NEA), requires that all on-grid renewable electricity enters the electricity market and that an out-of-market mechanism pricing settlement is established to ensure long-term price certainty for renewables. Provinces have established renewable mechanism pricing arrangements based on local conditions, completed transition arrangements for existing renewable projects, and organized bidding rounds for mechanism-covered volumes in 2025 and 2026.

Generation-side capacity pricing mechanisms are expanding to cover more resource types,[ii] with future compensation increasingly linked to peak-serving capability. The *Notice on Improving Generation-Side Capacity Pricing Mechanisms* allows, for the first time at the national level, the establishment of capacity pricing mechanisms for grid-side stand-alone energy storage. Once spot markets become operational, generation-side reliable capacity compensation mechanisms will be gradually established to more fairly reflect their contribution to meeting system peak demand.

---

i Twenty-nine provincial-level power grids include six provincial electricity spot markets that are officially operating and 18 provincial electricity spot markets under continuous settlement trial operation within the State Grid and Western Inner Mongolia Grid region, as well as the five provincial power grids covered by the Southern Regional Electricity Spot Market.

ii A capacity price compensates resources for providing dependable capacity to the power system, rather than paying only for electricity generated or discharged.

A capacity-based transmission and distribution (T&D) tariff was introduced to support local renewable energy consumption projects. Building on existing one-part (energy-only) and two-part T&D tariff structures, the NDRC and the NEA issued the *Notice on Improving Pricing Mechanisms to Promote Local Consumption of Renewable Power*, establishing a capacity-based T&D tariff approach for local renewable energy consumption projects. This approach is intended to better support project models such as direct green power connection.

The retail electricity market continues to be standardized, with stronger wholesale-to-retail price pass-through. Most electricity users purchase power through the retail market, making retail market design increasingly important for guiding user behavior and shaping load profiles. Whereas power market reform over the past decade focused primarily on wholesale market development, retail market improvement is a new frontier. In the next stage of retail market development, it will be critical to further standardize retail market rules, diversify retail contract structures, strengthen wholesale-to-retail price pass-through, improve market transparency, and cultivate buyer awareness among retail users.

Changes in system operation fees are reshaping end-user electricity bill structures. With the introduction of renewable mechanism pricing, adjustments to generation-side capacity pricing, and continued spot market development, the user-side electricity pricing mechanism has become clearer. Ancillary service fees, generation-side capacity fees, and renewable mechanism pricing settlement costs are being separated from the energy component of electricity prices and incorporated into system operation fees. As a result, system operation fees now account for a growing share of end-user electricity prices.

The year 2026 marks the beginning of China's 15th Five-Year Plan period and a new phase in the evolution of the unified national power market system. In February 2026, the General Office of the State Council issued the *Implementation Opinions on Improving the National Unified Power Market System* (Document No. 4), another landmark policy following the 2015 *Opinions on Further Deepening Power Sector Reform* (Document No. 9). Document No. 4 outlines key tasks for improving the unified national power market system over the next 5 to 10 years. By 2030, the system is expected to be largely complete, with all types of power sources and electricity users — except those protected electricity users — directly participating in the electricity market. By 2035, the unified national power market system is expected to be fully established, with more mature and complete market functions. Over time, markets are expected to more fully reflect the multidimensional value of electricity resources, including energy, flexibility, capacity, and environmental attributes, while supporting the initial formation of a nationally unified energy market system centered on electricity and coordinated across multiple energy sources.

RMI tracks China's power market reform, and has published the annual *China Power Market Outlook* report for market participants since 2023. The series reviews policy and market progress, identifies emerging trends, and provides market participants and other stakeholders with insights on power market development.

The 2026 edition systematically reviews major developments in China's power market and pricing system from the beginning of 2025 and provides a near-term outlook. The report follows a structure like the 2025 edition, with the first six sections organized by market component and the remaining sections organized by participant type. Given the pace of policy and market change over the past year, as well as space limitations, this report focuses on topics that have seen rapid progress or significant change and does not repeat market analysis already covered in previous editions. Major trends are summarized in Exhibit ES1. Readers may refer to the 2025, 2024, and 2023 reports for additional analysis of market and pricing developments. This English edition is tailored for international readers; a more detailed Chinese edition is also available.

Exhibit ES 1 **Ten key trends for power market players**

By market or pricing mechanism	Spot market	1. Provincial power spot markets now cover nearly all provinces, with spot prices emerging as the pricing anchor for medium- to long-term power and retail markets.
	M2L market	2. Time-segmented M2L trading has become widespread, with intraday price differentials constrained by trading price limits in some regions.
	Retail market	3. Wholesale-retail price pass-through is strengthening, and market-based TOU electricity pricing on the retail side is accelerating.
	Mechanism pricing	4. Mechanism pricing has been implemented nationwide, with notable disparities emerging in regional implementation plans, bidding outcomes, and settlement expenses across different regions.
	Capacity pricing	5. Capacity pricing is expanding to include more types of generation-side entities, with compensation depending on peak-serving capability.
	T&D tariffs and system operation fee	6. Capacity-based T&D tariffs mark a policy breakthrough, while system operation fees play a growing role in the overall electricity price structure.
By market entity	Energy storage	7. Stand-alone energy storage economics improve as capacity pricing rolls out, while market-based TOU pricing reshapes industrial and commercial storage operations.
	Virtual power plants	8. Generation-type virtual power plants are becoming a key route for distributed renewables to enter power markets.
	Green power trading	9. Green power supply-demand balance remains relatively loose, while expanding application scenarios drive demand for green energy certificates.
	Electric vehicles	10. Vehicle-to-grid pilots continue to expand, and provinces are beginning to introduce discharge pricing mechanisms.

RMI Graphic. Source: RMI

1. Provincial power spot markets now cover nearly all provinces, with spot prices emerging as the pricing anchor for medium- to long-term power and retail markets

Since April 2025, when the National Development and Reform Commission (NDRC) and the National Energy Administration (NEA) issued the *Notice on Comprehensively Accelerating the Development of the Power Spot Market,*[1] China's power spot market buildout has proceeded rapidly. By February 2026, provincial spot markets covered nearly the entire country. In the State Grid and West Inner Mongolia (Mengxi) regions, all except the Beijing-Tianjin-Jibei region and Xizang had launched continuous (trial) operation.[iii] Spot markets in Shanxi, Shandong, Gansu, West Inner Mongolia, Hubei, and Zhejiang, as well as the State Grid interprovincial spot market, had already entered official operation. The remaining 18 provincial markets in the State Grid area, including East Inner Mongolia and South Hebei, were in continuous trial operation. In the China Southern Power Grid region, the regional spot market covering Guangdong, Guangxi, Yunnan, Guizhou, and Hainan was also in continuous trial operation. Most markets that are currently in continuous trial operation are expected to move to official operation over the next one to two years.

Average spot prices continue to fall, and regional differentiation is becoming more pronounced

Across regions, average spot prices remained low in 2025 and were generally below local coal power benchmark prices. In most provincial or regional markets, the 2025 average spot price was below the local coal power benchmark price,[iv] with discounts ranging from 9.2% in Ningxia to 59.2% in Guangxi. Only South Hebei and West Inner Mongolia recorded average 2025 spot prices above the benchmark by 1.8% and 3.1%, respectively.[v, 2] Compared with 2024, the seven provincial spot markets in continuous (trial) operation — Shanxi, Shandong, West Inner Mongolia, Zhejiang, Hubei, Gansu, and Guangdong — together with the State Grid interprovincial spot market, recorded year-on-year declines in average prices ranging from 1.5% in Gansu to 42.4% in West Inner Mongolia. One key driver was lower thermal coal prices. For example, the annual average price of 5,500 kcal thermal coal in the Qinhuangdao seaborne market was RMB 695/ton in 2025, down 19.2% year on year.[3]

iii The Hebei provincial grid has two parts. "Jibei" refers to the North Hebei portion.

iv For provinces and regions that continuously operated for only months but not a full year in 2025, we used data from the available months.

v Among regions with continuous operation, data for Jilin, Shanghai, Hunan, Sichuan, and Chongqing was unavailable; those regions are therefore excluded from this analysis.

Spot price levels vary widely across regions, shaped by local coal prices, renewable generation profiles, load patterns, and winter heating constraints, with clear seasonal effects in many markets. Exhibit 1 summarizes average real-time prices in representative months of 2025 across selected provincial spot markets in continuous (trial) operation. In summer (July–August), Yunnan and Guangxi in the China Southern Power Grid regional spot market were affected by the wet season, and their average spot prices fell well below those in other regions, reaching RMB 87/megawatt-hour (MWh) and RMB 151/MWh, respectively. In northwestern China, Gansu also benefited from stronger upstream Yellow River hydropower output in summer, with an average spot price of RMB 211/MWh, compared with RMB 245/MWh in the dry season (November–December). By contrast, most central and eastern provinces remained above RMB 250/MWh in summer. In winter, spot prices in northern provinces — including Heilongjiang, Liaoning, West Inner Mongolia, Shanxi, Shandong, South Hebei, and Shaanxi — generally moved into a lower price band, reflecting strong winter wind output, thermal load to support heating on combined heat and power units, and winter demand that remained below summer peaks. In southern provinces with hot summers and cold winters, such as Anhui, Zhejiang, and Hubei, electric heating demand and relatively stable industrial activity kept winter loads high — sometimes above summer levels — supporting spot prices that were on par with, or even higher than, summer prices.

Some spot markets have also shown distorted price signals. In addition to market fundamentals, early-stage operational factors — such as forecasting capability, administrative intervention, and participants' level of risk management maturity — can affect price formation.[4] Heilongjiang is a representative example. In December, severe cold weather reduced part of the productive load, while wind capacity, which accounts for about one-third of provincial installed capacity, was in a high-output season. At the same time, traditional combined heat and power units, constrained by heat supply obligations, had limited ability to reduce output, creating a pronounced supply-demand imbalance.[5] On the operational side, the market operator's day-ahead renewable generation forecasts were often higher than actual output, which narrowed the bidding space calculated for the day-ahead market and intensified price competition among generators.[vi] In addition, day-ahead offers were used for real-time market clearing. Together, these factors drove extremely low real-time prices: an extended period of zero prices pushed the monthly average down to RMB 57/MWh, which was not an accurate reflection of underlying supply-demand conditions or actual system costs.[6]

vi Bidding space is the amount of load still available for bidding after accounting for interconnection flows, wind generation, and solar PV generation. For an analysis of its positive correlation with spot prices, see *2024 China Power Market Outlook: 10 Key Trends for Market Players*.

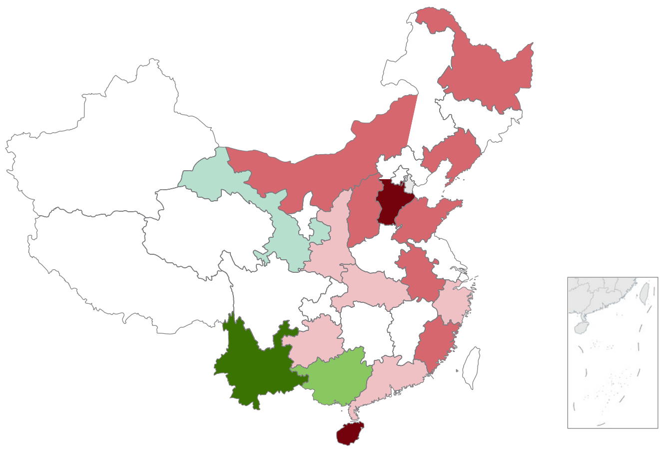
Exhibit 1 **Average real-time market spot prices in selected provincial markets (representative months, 2025)**

Average real-time spot prices

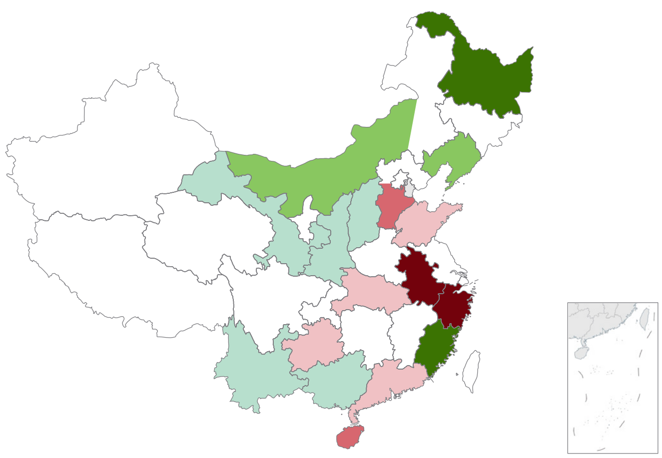
■ ⩾ 350 ■ [300, 350) ■ [250, 300) ■ [200, 250) ■ [150, 200) ■ <150

□ Data unavailable / Spot market not in continuous operation

Summer (July–October)



Winter (November–December)



Note: Exhibit includes 17 provincial spot markets that were in continuous (trial) operation from summer through winter 2025. Heilongjiang entered continuous trial operation on August 1, 2025, so its summer average reflects August only.

RMI Graphic. Source: Lambda Power Spot Market; RMI

Spot prices are strengthening time-of-use price signals and enabling more granular transactions in medium- to long-term and retail markets

In September 2025, the NDRC and the NEA issued the *Guidelines for Market Construction in Regions with Continuous Operation of Power Spot Markets*.[7] The guidelines call for gradually aligning price caps for shorter-cycle medium- to long-term (M2L) products, such as monthly and intramonth transactions, with spot market price caps. They also emphasize strengthening price pass-through from wholesale to retail markets and encouraging retailers and end-users to design retail packages more flexibly and adopt time-of-use (TOU) contracts. This suggests that the intraday price curve formed in the spot market is increasingly becoming the reference point for negotiating time-differentiated prices in both M2L transactions and retail contracts.

As M2L market rules continue to evolve, spot prices are playing a stronger role in shaping time-segmented contracting. In December 2025, the NDRC and the NEA issued the revised *Basic Rules for the Medium- to Long-Term Power Marke*t.[8] The rules clarify that, for entities directly participating in market transactions, TOU price levels and time periods will no longer be set administratively. For customers supplied through grid-proxy purchase,[vii] pricing authorities will coordinate and optimize peak-valley time periods and price fluctuation ranges with reference to spot price levels. This means direct market participants can negotiate time-differentiated contract prices with generators, further strengthening the role of spot prices as the pricing anchor for time-segmented M2L products. Even for grid-proxy users, TOU period definitions and price levels are expected to be adjusted continuously in response to spot price signals. (For M2L TOU practices, see Section 2; for retail TOU practices, see Section 3.)

As more provinces move — where conditions allow — from one-sided generator bidding to two-sided bidding by both generators and users,[viii] price signals are likely to reflect supply-demand conditions more accurately and reveal system value more granularly. The *Guidelines for Market Construction in Regions with Continuous Operation of Power Spot Markets* call for joint participation by generators and users in the spot market and encourage new participants — such as virtual power plants (VPPs), smart microgrids, novel energy storage, and user-side entities — to participate through volume-and-price bidding. Load-type VPPs have already entered spot markets through volume-and-price bidding in several provinces (see the *Virtual Power Plants* section in the 2025 edition of this report).

On the demand side, following Gansu, where two-sided bidding has already been implemented, more provinces are launching pilots. For example, the latest *Shandong Power Market Rules (Trial)*, issued in December 2025, state that day-ahead economic dispatch will use a centralized optimization mechanism based on volume-and-price bids from both generators and users, and that wholesale users and retailers may participate voluntarily. As of the end of January 2026, 224 demand-side entities in Shandong — or 75% of all demand-side entities in the province — had chosen to submit volume-and-price bids for day-ahead economic dispatch.[9] The *Implementation Opinions on Improving the National Unified Power Market System*, issued in February 2026,[10] again emphasized broad participation by market entities on both the generation and load sides through volume-and-price bidding.

---

vii Following the removal of regulated catalog tariffs for industrial and commercial (I&C) users in 2021, I&C users connected at 10 kV and above are, in principle, required to directly participate in the power market — purchasing electricity from either generators or electricity retailers. Users that are temporarily unable to participate directly may procure electricity through grid companies on behalf of users.

viii In most provinces, spot market clearing currently uses a model in which generators submit both volume and price bids, while demand-side participants submit volumes only without price bids.

2. Time-segmented M2L trading has become widespread, with intraday price differentials constrained by trading price limits in some regions

In December 2025, the NDRC and the NEA jointly issued the *Basic Rules for the Medium- to Long-Term Transactions* ("The Rules").[11] The Rules took effect on March 1, 2026, with a validity period of five years.

The Rules establish an M2L trading system with time frames ranging from multiyear and annual to monthly and intramonth periods. To improve market flexibility and facilitate coordination with the spot market, the Rules require that intramonth trading be opened on a daily basis and that the possibility of continuous trading for multiyear, annual, and monthly products be explored.

The Rules eliminate administrative TOU pricing in the wholesale electricity market,[ix] allowing prices to be determined by the market. Over the past few years, as time-segmented M2L transactions have gradually rolled out across various regions, market-based intraday time-segmented price signals have begun to take shape.

Time-segmented M2L transactions have become widespread, and the transaction price is gradually decoupling from administrative time-of-use (TOU) pricing

By 2026, most regions had launched time-segmented M2L transactions, though the methods for dividing trading periods vary across regions. Most regions have adopted a consistent segmentation approach for different trading cycles (annual, monthly, and intramonth), primarily using a 24-period division corresponding to the hours of the day.

Some regions are exploring two main alternative approaches to time-period segmentation. One aims to strengthen alignment with the spot market by using more granular segmentation beyond the 24-period model. Jiangxi, for example, has adopted a 48-period model. In another approach, a few regions have introduced differentiated time-segmented trading rules for annual versus monthly transactions, applying coarser segmentation to annual trading and finer segmentation to monthly trading.

ix "Administrative" pricing refers to prices set by the government.

For time-segmented trading, the price limit for long-term cycles is set at the coal power benchmark price ±20%, while for short-term cycles it closely follows the spot market limit

When setting price limits for annual time-segmented transactions, most regions generally refer to coal power benchmark price with a ±20% floating range, requiring that transaction prices for all time periods fall within this band. Against the backdrop of persistently low thermal coal prices, some regions have maintained the upper price limits while relaxing the lower limits in their 2026 annual M2L time-segmented transactions. Specifically, West Inner Mongolia, Jilin, and Sichuan have set the lower limit at RMB 0/MWh; Shaanxi has set it at RMB 100/MWh; and Ningxia has lowered it to −40% of coal power benchmark price. Xinjiang has taken a different approach, shifting the entire price band downward by RMB 30/MWh while keeping the ±20% floating range intact.

Most regions generally refer to spot trading price limits as the price limits for intramonth time-segmented transactions. For price limits on monthly M2L time-segmented transactions, regions have mainly adopted two approaches: either using the coal power benchmark price with a ±20% floating range (referencing annual transactions) or using spot trading price limits (referencing intramonth transactions).

Most regions adopt a uniform price limit model across all time periods. Shanxi and Guangdong, however, have introduced time-segmented characteristics into their segmented transaction price limits, setting different price limit ranges for different time periods. Both provinces base their calculations on the spot trading price curve and adjust the price limit range based on the coal power benchmark price (in Shanxi) or the market reference price (in Guangdong).

Due to trading price limits, intraday peak-to-valley price fluctuations in M2L time-segmented transactions are limited in certain regions

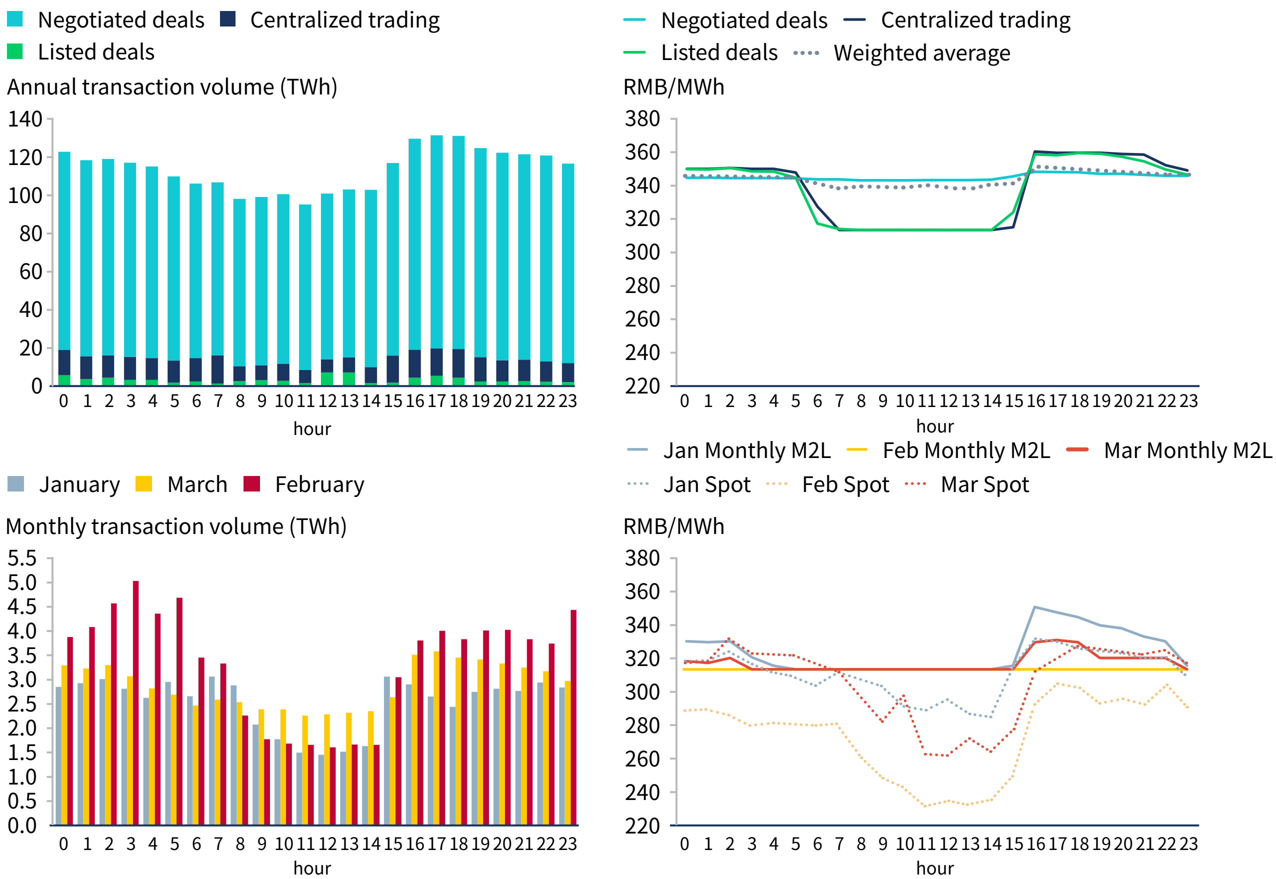
Jiangsu's setup for M2L time-segmented transactions reflects the common practice across most regions: trading periods are divided into the 24 hours of the day, price limits for annual and monthly transactions are set at the coal power benchmark price with a ±20% floating range, and spot price limits are adopted for intramonth transactions. Jiangsu's M2L electricity trading results provide a representative case to analyze the actual outcomes of time-segmented transactions (see Exhibit 2).

Price fluctuations in Jiangsu's M2L time-segmented trading are generally limited but vary by trading method and cycle. Of the trading methods, centralized trading produces a more volatile time-segmented price curve than bilateral negotiations. In Jiangsu's 2026 annual transactions, negotiated deals saw price fluctuations of ±1% across time periods, while listed and auction-based transactions saw fluctuations of up to ±7%. Comparing trading cycles, there is less price volatility in monthly centralized trading than in annual centralized trading. In Jiangsu's monthly centralized bidding from January to March 2026, midday prices matched the annual centralized floor price, but morning and evening peak prices were lower than those in annual centralized trading.

Jiangsu's M2L time-segmented transactions largely reflect intraday supply-demand dynamics. The local load curve has morning and evening peaks, with a midday low that coincides with high renewable output. As a result, time-segmented transactions show higher prices in the morning and evening, and lower prices at midday — matching both intraday supply-demand and the shape of the spot price curve. In February 2026, due to the Spring Festival holiday, weak demand pushed monthly time-segmented prices to the lower limit (20% below the coal power benchmark price) across all periods, forming a flat curve.

Trading price limits primarily account for the lower price volatility in Jiangsu's monthly centralized bidding transactions than in spot trading. Bound by the coal power benchmark price ±20% band, monthly transaction prices at midday cannot fall below 20% of the benchmark, while spot prices during that period often drop further. For example, in February 2026, spot prices stayed below the –20% level all day, but monthly time-segmented prices were floored at the lower limit, forming a flat curve. Overall, with coal prices currently low, the –20% lower limit on M2L time-segmented transactions suppresses intraday price fluctuations.

Exhibit 2 **Time-segmented trading results in Jiangsu: 2026 annual transactions vs. monthly centralized bidding, January–March 2026**



RMI Graphic. Source: Jiangsu Power Exchange Center; Lambda Power Spot Market

With the strengthening pass-through from wholesale to retail markets, price signals from M2L time-segmented transactions are increasingly transmitted to the retail side, thereby shaping the price curves faced by retail users. As a result, retail users with rates linked to wholesale time-segmented prices will likely experience a smoother price curve.

The move toward M2L time-segmented transactions demands more of market participants in three key ways. First, bidding becomes more complex. Instead of simply splitting volumes along a single curve, participants must submit volume and price bids for each period, requiring greater precision. Second, price uncertainty increases. Unlike the administrative TOU signals of the past, segmented trading prices formed by the market are more volatile and can vary across trading cycles (e.g., annual versus monthly) and methods (e.g., bilateral versus centralized bidding), making price trends harder to predict. Third, revenue estimation and strategy formulation become more challenging. Higher price uncertainty directly affects revenue projections and trading decisions.

3. Wholesale-retail price pass-through strengthens, and retail-side use of market-based TOU electricity pricing accelerates

As the construction of electricity spot markets accelerates, China's wholesale electricity market is becoming increasingly sophisticated. At the same time, retail market development continues to be standardized, and the link between the wholesale and retail markets is steadily strengthening. On September 12, 2025, the NDRC and the NEA issued the *Notice on Issuing the Guidelines for Market Construction in Regions with Continuous Spot Market Operation*.[12] This document calls for diversifying retail market trading methods, promoting wholesale-retail price pass-through, and enhancing retail market transparency.

Retail packages align more closely with the wholesale market, better reflecting the average wholesale market price

For 2026 retail electricity packages, 16 regions explicitly require that the prices for all or a portion of the electricity volume be linked to wholesale market prices, thereby enabling wholesale-retail price pass-through for more retail users. There are three categories of packages distinguished by the degree of pass-through: full-volume pass-through, partial-volume pass-through, and no mandatory pass-through. Due to regional differences in package structures and the required proportions of pass-through volume, the extent to which retail users' final electricity prices are affected by wholesale market prices can vary significantly.

- In regions classified under full-volume wholesale-retail price pass-through, fixed-price packages are no longer offered to retail users. Users can only sign price-linked or price-difference sharing packages, where all electricity prices are formed via pass-through from wholesale market prices.

- Regions using partial-volume wholesale-retail price pass-through offer combined "fixed price plus wholesale-retail pass-through" packages, requiring that a certain proportion of the user's electricity volume be subject to wholesale-retail price pass-through, while the remaining portion is still contracted at a fixed price.

- In regions where wholesale-retail price pass-through is not mandatory, fixed-price packages remain available, and users can still sign retail packages with prices that are not subject to pass-through from wholesale market prices.

In promoting wholesale-retail price pass-through for retail packages, most regions have adopted a mechanism linked to the average wholesale market price. This approach decouples users' electricity prices from the actual trading performance of their chosen retailer, thereby reducing price disparities resulting from retailer selection. Under this pass-through mechanism, retail users can estimate their electricity price levels based on the wholesale price information published by the market operator.

When calculating the average wholesale market price, most retail packages with wholesale-retail pass-through use a weighted average of M2L and spot market prices. The electricity volume ratio generally reflects actual wholesale market trading conditions, meaning the share of M2L transaction prices typically exceeds 80%. As a result, retail package prices linked to the wholesale market are primarily influenced by M2L transaction price levels. With greater coordination across the electricity market system, spot prices will increasingly influence wholesale averages, pulling retail electricity prices into tighter alignment with the spot market.

Retail TOU pricing is gradually transitioning to a market-based model, but progress differs by region

Most regions have now fully implemented TOU pricing contracts for all retail market participants, with the aim of guiding users to optimize their electricity consumption. There are two main models of TOU pricing mechanisms for retail packages. Both models can be applied to either the fixed-price portion or the wholesale-retail pass-through portion of the electricity volume.

- **Under the administrative TOU model:** The fixed-price portion sets a base (off-peak) price, and the wholesale-retail pass-through portion derives its base price from the wholesale market average. In both cases, peak and valley prices are then generated from the base price according to administrative TOU rules.

- **Under the market-based TOU model:** The fixed-price portion sets prices for each period, while the wholesale-retail pass-through portion forms its prices via the pass-through of wholesale market prices for the corresponding time periods.

Retail packages in some regions have shifted from the administrative model toward the market-based model. Currently, about 62% of regions have adopted a market-based TOU model for retail packages; 28% still follow the administrative TOU model; and the remaining 10% operate both in parallel (see Exhibit 3).

Over the long term, power market reforms will phase out administrative TOU electricity pricing across all wholesale and retail markets. As M2L time-segmented transactions and wholesale-retail pass-through improve, more regions are likely to adopt market-based TOU pricing on the retail side. Retail users will need to actively monitor wholesale time-segmented price signals and accurately assess costs based on their own consumption profiles.

Exhibit 3 **Configuration of retail package types across regions in 2026**

Region	Retail package type				Retail package TOU model		
	Fixed-price package	Price-linkage package	Proportional-split package	Fixed price + wholesale-retail pass-through package	Administrative TOU model	Market-based TOU model	Requirement: Market TOU float range ≥ administrative TOU float range
Coverage ratio	48%	83%	55%	41%	34%	72%	10%
Beijing	✓	✓	✓		✓		
Tianjin			✓		✓		
South Hebei		✓				✓	
Jibei	✓	✓	✓		✓		
Shanxi		✓				✓	
Liaoning	✓	✓	✓			✓	
Jilin	✓	✓	✓			✓	
Shanghai		✓		✓	✓		
Jiangsu	✓ (Old version)	✓ (Old version)	✓ (Old version)	✓ (New version)	✓	✓	✓
Zhejiang	✓	✓	✓				
Anhui		✓	✓	✓		✓	
Fujian	✓	✓	✓			✓	
Jiangxi			✓	✓		✓	✓
Shandong	✓	✓		✓		✓	
Henan	✓	✓	✓			✓	
Hubei		✓				✓	
Hunan		✓	✓			✓	✓
Guangdong		✓		✓	✓		
Guangxi		✓ (During spot market operation periods)		✓ (During non-spot market operation periods)		✓	
Hainan				✓	✓		
Chongqing	✓	✓	✓			✓	
Sichuan				✓	✓ (Fixed-price portion)	✓ (Wholesale-retail pass-through portion)	
Guizhou				✓	✓ (Fixed-price portion)	✓ (Wholesale-retail pass-through portion)	
Yunnan	✓	✓		✓	✓		
Shaanxi		✓		✓		✓	
Gansu	✓	✓	✓			✓	
Qinghai		✓				✓	
Ningxia	✓	✓	✓			✓	
Xinjiang	✓	✓	✓			✓	

Note: Regions with missing information are not listed.

RMI Graphic. Source: Regional Power Exchange Center

Regions adopt measures to mitigate electricity price risk to users

Limited transparency, uneven retailer quality, and incomplete wholesale-retail pass-through have led to two key problems in the retail market. First, some retailers fail to pass on wholesale cost savings to users to reap greater profit. Second, some retailers acquire users by offering ultra-low prices and then fail to deliver, creating price uncertainty. To address these issues, regions have introduced various targeted measures, including excess-profit-sharing mechanisms, upper and lower price limits on transactions, and price caps on retail packages. These measures aim to keep user electricity price fluctuations within a reasonable range and pass wholesale market price reductions to users, ensuring stable and affordable electricity.

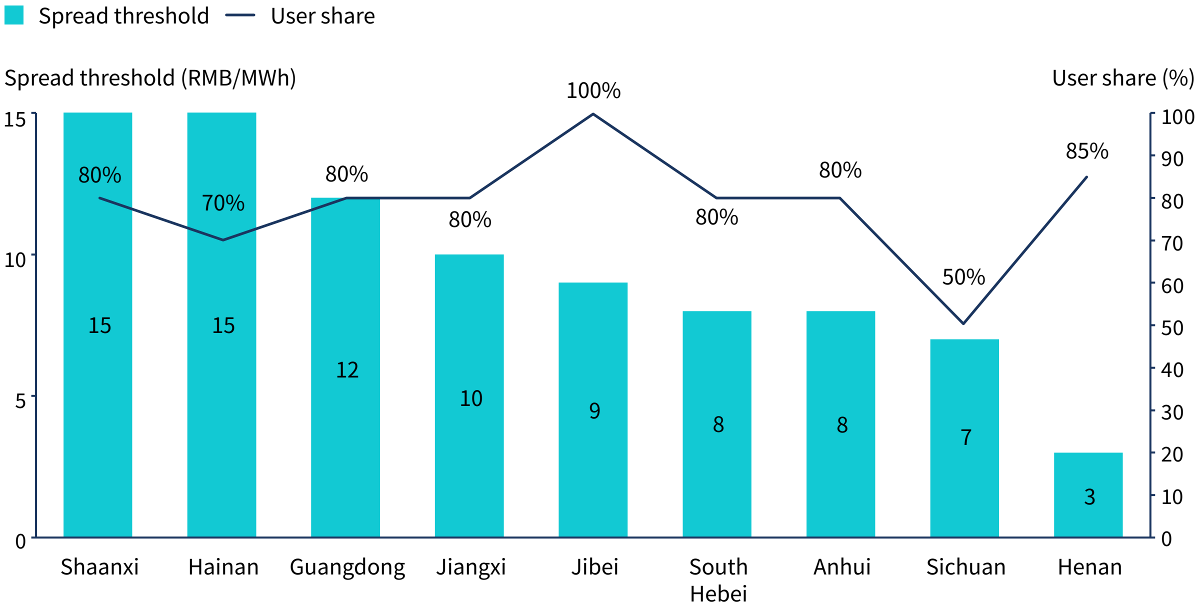
The following analysis will show that some of these measures are short-term responses to current problems. As wholesale-retail pass-through advances and the retail market matures, transparency will improve and these issues will gradually ease. These developments may increase the importance of retailer selection and contract structure for retail users and may place greater emphasis on cost management and service quality among retailers.

Risk control approach 1: Employing an excess-profit-sharing mechanism in the retail market to pass price reductions on to users

In recent years, due to low coal prices, rapid growth in renewable energy capacity, and the introduction of coal-fired capacity prices, China's electricity prices have been trending down. Some electricity retailers have leveraged their information and resource advantages to optimize power purchase arrangements across different trading cycles, achieving high wholesale-retail price spreads (i.e., the difference between the average wholesale purchasing price and the average retail selling price). For instance, in Anhui province from January to December 2025, the average wholesale-retail spread was RMB 21.22/MWh, with about 5% of signed contracts seeing spreads above RMB 40/MWh.[13]

To effectively constrain excess profits of electricity retailers, some regions have been exploring an excess-profit-sharing mechanism in the retail market since 2025. This mechanism requires retailers to share the gains from wholesale-retail price spreads with users, typically through monthly settlements. For the 2026 retail market, regions differ in their spread thresholds and sharing ratios (see Exhibit 4). The sharing ratios are generally heavily tilted in favor of users, with most regions setting the user's share at around 80%. Regions that have explicitly introduced spread thresholds have set them within a range of RMB 3–15/MWh. The lower the spread threshold, the less excess profit retailers can retain and the more users can benefit from electricity price reductions driven by wholesale market declines.

Exhibit 4 **Spread thresholds and user shares in regional retail excess-profit-sharing mechanisms**



RMI Graphic. Source: Regional Power Exchange Center

It's worth noting that the current excess-profit-sharing mechanism mainly applies during periods of falling electricity prices. However, existing rules rarely address whether retail users should share the costs when electricity prices result in negative wholesale-retail spreads for retailers. Guizhou is currently the only province that has clear provisions on this issue. It requires users to share both excess profits and losses from negative spreads, applying the same thresholds and ratios in both directions. Specifically, Guizhou sets the spread threshold at ±3% of the wholesale settlement average price, with the user share set at 80% for both profit and loss scenarios.[14]

The excess-profit-sharing mechanism in the retail market is a transitional policy aimed at balancing trading capability disparities between retailers and users in the early stages of market development. As wholesale-retail price pass-through improves, retail prices are expected to return to market-based pricing with less administrative intervention. Shaanxi province, for example, no longer mentions the excess-profit-sharing mechanism in its draft retail market rules released on March 18, 2026.[15] In the long run, regulating retailers will shift from price intervention toward greater information transparency, stronger competition, and better market rules — encouraging retailers to innovate and expand value-added services.

Risk control approach 2: Strictly capping the price limits for the fixed-price portion of electricity to prevent malicious ultra-low-price competition among retailers

In late 2025, during the signing of 2026 retail electricity contracts, ultra-low price offers emerged in Guangdong and Jiangsu. Some retailers quoted prices below the regulatory floor (–20% of coal power benchmark price) to capture market share and lock in users early. In response, local electricity trading centers issued risk warnings, urging retailers not to use ultra-low prices to lure users and advising users to monitor wholesale price trends and assess the potential performance risks of such contracts.

To prevent malicious ultra-low-price competition, Guangdong and Jiangsu have enforced price caps and floors on the fixed-price portion of electricity, aligning with annual wholesale market trading limits. Jiangsu has also promoted wholesale-retail pass-through packages to reduce retail contract performance risks. As wholesale-retail price pass-through continues to strengthen, ultra-low-price competition that ignores actual market costs will likely diminish.

Risk control approach 3: Introducing price caps on retail packages to prevent excessively high electricity prices for retail users

Some regions have introduced price caps on retail packages, setting an upper limit on the settlement price paid by retail users. Typically linked to wholesale electricity market prices, these caps help prevent retail prices from becoming excessively high relative to wholesale market levels, while ensuring that users benefit from cost reductions resulting from declining wholesale market prices.

The retail package price cap is required by the provincial power exchange center in the package contract template and users have the option to apply the price cap on their retail package or not and does not vary by package type. Regions set price caps in two ways depending on whether they are linked to the user's consumption profile. In the first approach, the cap is a uniform markup on the wholesale average price applied to all users, though the markup percentage varies. In the second approach, the cap is user specific. A reference price is calculated by weighting wholesale prices according to the user's time-segmented consumption, and the cap is then set as a markup on that reference price. This mechanism accounts for cost differences arising from varying consumption behaviors.

4. Mechanism pricing has been implemented nationwide, with notable disparities emerging in regional implementation plans, bidding outcomes, and settlement expenses across regions

In January 2025, the NDRC issued the national-level *Notice on Deepening the Market-Based Reform of Renewable Energy On-Grid Pricing to Promote High-Quality Development of Renewables* (hereafter referred as Document No. 136), with provincial implementation policies rolling out beginning in July. This marks a new stage in China's renewable on-grid price regime, featuring full market participation plus partial over-the-counter guarantee mechanisms.

According to policymakers, the aim is to use market-based tools to continue supporting renewable energy deployment. Both existing and new wind and solar projects are required to participate in the electricity market — but under different mechanism pricing formulations.

Existing projects connected to the grid before June 1, 2025, have the mechanism pricing and covered volume aligned with the feed-in tariff policy that applied to the project before mechanism pricing took effect. For projects connected to the grid on or after June 1, 2025, part or all their generation may be eligible for mechanism pricing — with the price determined through competitive bidding and the implementation term based on the average initial investment payback period of comparable projects.

All regions nationwide have rolled out bidding for renewable mechanism pricing, with significant differences in bidding plans and results

The implementation of mechanism pricing across China (excluding Xizang, Hong Kong, Macao, and Taiwan) has developed in phases, with early launch in eastern regions and progressive advancement in central and western areas, gradually going into regular operation nationwide. As of this year, mechanism pricing has been fully implemented for existing projects, and bidding for new projects has been normalized. Provinces including Xinjiang have launched second-round bidding. Furthermore, Jiangsu, Fujian, and Hainan have formulated dedicated bidding schemes for offshore wind power.

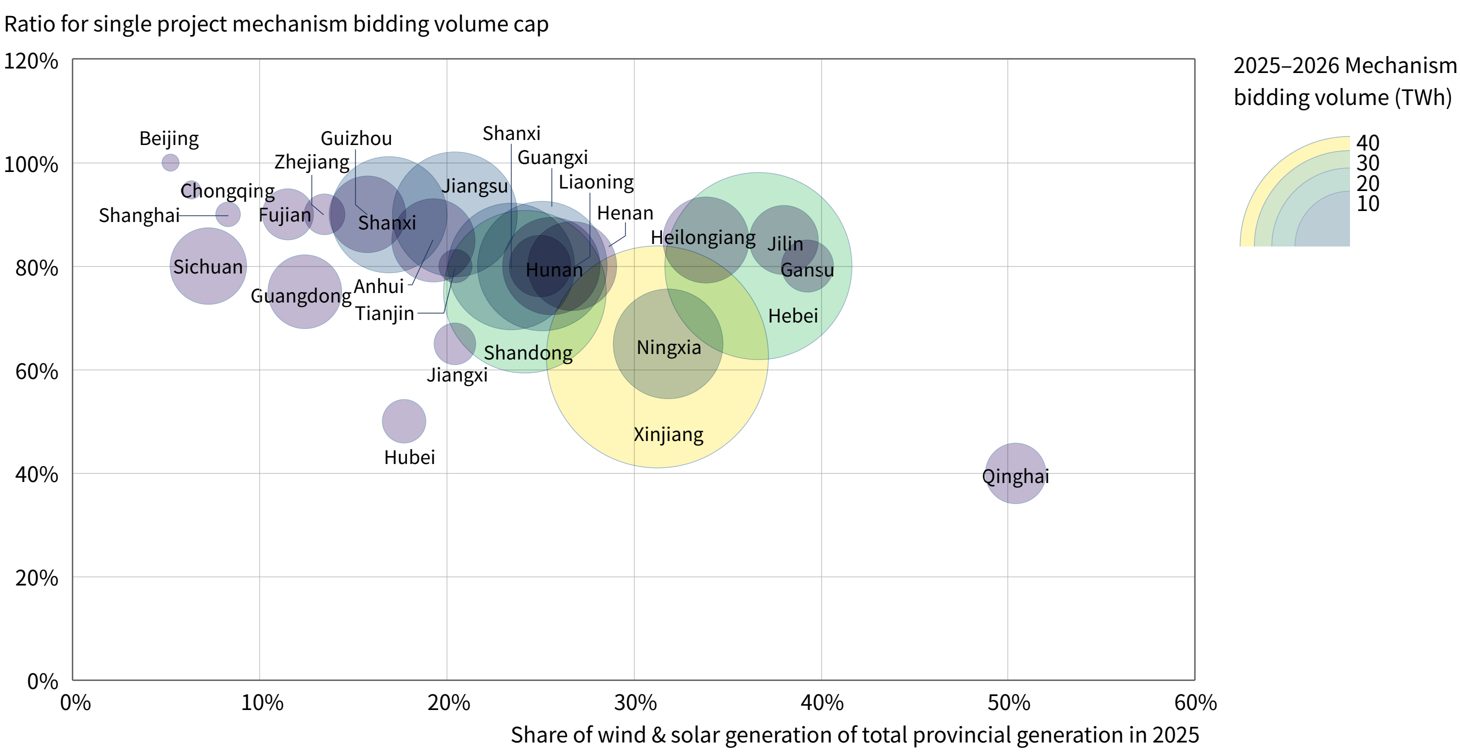
The total announced bidding volume for power nationwide has reached approximately 220 TWh, of which around 180 TWh has been officially settled. Provincial arrangements for new projects' mechanism pricing power volume vary considerably.

- From a geographic perspective, overall bidding volume is taking place at a larger scale in parts of northwest China and northeast China, while in central and southwest China volumes remain smaller. Eastern coastal provinces show significant differences in scale (see Exhibit 5).

- The upper-limit ratio of power generation eligible for mechanism pricing differs sharply among provinces. For new projects, the eligible power volume ranges from 40% to 100% of the total. Provinces with a lower share of renewable power generation tend to set a higher access ratio for individual projects to apply mechanism pricing (see Exhibit 5). For existing projects, implementation generally follows the basic principle of default access to mechanism pricing with prices free from market volatility. However, huge disparities exist in the inclusion ratio of mechanism pricing power volume across regions. In Shanghai and Beijing, the maximum inclusion ratio is 100%; centralized grid-parity projects in Shanxi have an 85% inclusion ratio; and merely 10% of power volume from centralized wind and photovoltaic projects in Ningxia are incorporated into mechanism pricing.

- In terms of technical distribution, all provincial-level regions except Anhui have clearly separated mechanism pricing power volume between wind power and photovoltaic power. Nationwide, among all announced bidding power volume, wind power accounts for 61% and photovoltaic power accounts for 39%. Wind power takes up more than half of the mechanism pricing volume in most provinces, exceeding 80% in the three northeastern provinces, Guangxi, and South Hebei power grid. In contrast, photovoltaic projects account for all mechanism pricing power volume in the four southeastern coastal provinces: Jiangsu, Zhejiang, Fujian, and Guangdong.

Exhibit 5 **Mechanism bidding volume by region and projects, and portion of renewable power in total generation by region**



RMI Graphic. Source: Regional Power Exchange Center

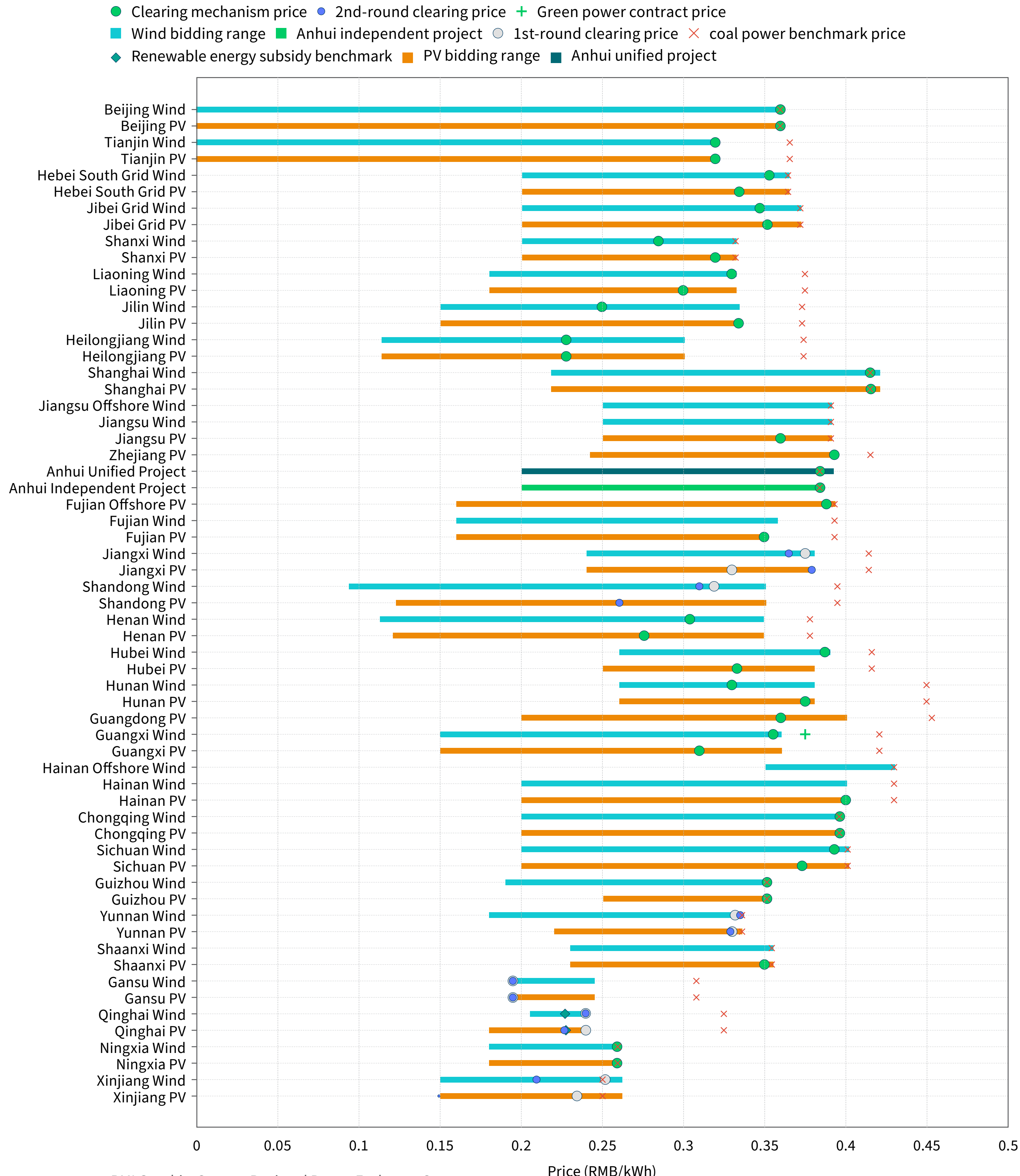
Mechanism pricing for new projects results in varying electricity prices across regions, power source types, and bidding rounds (see Exhibit 6).

- Provincial bidding results differ markedly across regions — in terms of both absolute prices and the range in price decline compared with the local coal power benchmark. For instance, provinces with the largest price declines are in northwestern and northeastern China, including a 39% drop for wind and photovoltaic power in Heilongjiang, a 36.5% decline for wind power in Gansu, and a 40% decrease for photovoltaic power in Xinjiang. Nevertheless, some provinces in these regions, such as Ningxia and Shaanxi, record a price decline of less than 5%. The absolute values of mechanism pricing in central provinces are generally at the medium level. In terms of price decline, the mechanism pricing in Anhui is roughly equivalent to the local benchmark coal-fired power price, while the decline in Henan, Jiangxi, Hunan, and other provinces is around 20%. Eastern coastal provinces also see a marked price divergence. The price decline in most eastern China provinces is within 10%. By contrast, the first-round mechanism pricing for photovoltaic power in Shandong stood at only RMB 0.225/kWh — a 43% drop against the local benchmark coal-fired power price. This reflects the strong generation supply of photovoltaic power. In the second round of photovoltaic power bidding in Shandong, the price rebounded to RMB 0.261/kWh. In South China, the cleared mechanism pricing in Guizhou is on par with the local coal power benchmark prices, while the price decline in other southern provinces ranges from 15% to 27%.

- Employing mechanism pricing, the gap between wind power and photovoltaic power prices varies widely among provinces, indicating that it is a comprehensive embodiment of technology costs, market value, and policy guidance. Nationwide, the average new projects' mechanism pricing stands at RMB 0.3315/kWh for wind power and RMB 0.3255/kWh for photovoltaic power — an insignificant difference. Among provinces where both wind and photovoltaic power are allocated mechanism pricing power volume, roughly one-third set identical cleared mechanism pricing for the two power sources, including provinces that adopt unified pricing regardless of power types. In other provinces, the cleared mechanism pricing of wind power is mostly higher than that of photovoltaic power. Shandong is a typical example, where the price gap reaches RMB 0.094/kWh. This conforms to the market pricing logic that the characteristics of wind power output are a better match to local power system demand, together with targeted policy guidance. A small number of provinces show the opposite trend. In Jilin and Shanxi, the cleared price of photovoltaic power is RMB 0.084/kWh and RMB 0.035/kWh higher, respectively, than that of wind power, which largely reflects local wind-solar resource endowments and local policy.

- Among bidding results from different rounds within a given province, there is no distinct unified trend at present, due to short time intervals between rounds and different power technologies covered. Provinces that have completed two rounds of mechanism pricing bidding for new projects include Gansu, Jiangxi, Shandong, Xinjiang, Qinghai, and Shanxi. The second round of bidding in Jiangxi mainly targeted distributed photovoltaic power and small and medium-sized wind power projects. The unit construction cost was moderately higher, which drove up the cleared price compared with the first round. The second-round bidding results in Gansu, in northwestern China, are basically consistent with the first round, with all cleared prices hitting the lower limit of the bidding range. In Xinjiang, the prices in the second round dropped from the already low prices of the first round, with photovoltaic power price falling by 36%, both fully reflecting fierce market competition.

Exhibit 6 **Mechanism pricing bidding range and results**



RMI Graphic. Source: Regional Power Exchange Center

Nationwide, industrial and commercial power users are paying widely different rates under mechanism pricing

Following the nationwide rollout of bidding for mechanism pricing, the corresponding fees for renewable energy sustainable development price-difference settlement (hereafter referred to as price-difference settlement fees) have been formally integrated as an independent line item within the system operational costs included in industrial and commercial (I&C) electricity bills. As of April 2026, all provincial-level power grids (excluding Xizang) have released monthly price-difference settlement fee data. Two primary factors determine the size of these fees: first, the proportion of renewable generation eligible for mechanism pricing relative to local I&C electricity demand; a higher proportion implies a greater fee burden per unit of electricity for I&C users. Second, fee levels are governed by the spread between provincial market transaction prices and applicable mechanism pricing. Where the average market clearing price of renewable energy falls below mechanism pricing, I&C users are required to pay additional settlement fees to secure guaranteed revenue for renewable energy assets. Based on aggregated data from the first four months of 2026, monthly price-difference settlement fees exhibit substantial interprovincial disparities, with distinguishable trends summarized as follows.

Among the 32 provincial power grids, 28 posted positive cumulative price-difference settlement fees over the January–April period. Hainan, Shandong, Liaoning, Eastern Inner Mongolia, and Henan recorded monthly average fees exceeding RMB 60/MWh. Notably, although Eastern Inner Mongolia has not introduced mechanism pricing for new projects, its large stock of operational renewable energy projects has driven considerable settlement fees. Sixteen provincial grids maintained monthly average fees above RMB 20/MWh, dispersed across the Northwest, North, South, Central, and Northeast regions without evident geographical clustering. All 28 of the grids posting positive price-difference settlement fees have implemented continuous electricity spot market operations. The prevailing market price of renewable energy is determined by the monthly weighted average transaction price of comparable generation assets in real-time power markets. Relatively low market transaction prices paired with elevated mechanism pricing widen the price spread, thereby pushing up settlement fees. Conversely, when market transaction prices surpass mechanism pricing, negative settlement fees occur. Gansu serves as a representative case: the cleared mechanism pricing for onshore wind projects remained below the 2025 annual average realized price for wind, whereas mechanism pricing for photovoltaic projects exceeded the 2025 annual average realized price. The offsetting price dynamics resulted in an average settlement fee near zero for Gansu throughout the first four months of 2026 (see Exhibit 7).

Exhibit 7 **2025 annual average realized price for renewables, mechanism pricing, and price-difference settlement fees, January–April 2026**

RMB/MWh Province	Solar annual realized price	Solar clearing mechanism price	Solar price difference	Wind annual realized price	Wind clearing mechanism price	Wind price difference	Price-difference settlement fees, January–April 2026
Shandong	136	243	107	277	315	37	72
Liaoning	234	300	66	180	330	150	69
Henan	213	276	63	250	304	54	67
Shaanxi	116	350	234	223	352	129	58
Shanxi	130	320	190	237	285	47	51
Jiangxi	159	355	196	341	370	29	35
Hubei	170	333	163	284	387	103	19
Sichuan	209	373	164	234	393	159	15
Gansu	127	195	68	218	195	-23	0

RMI Graphic. Source: Regional Power Exchange Center

Four provincial grids — Beijing, Tianjin, Jibei, and Shanghai — reported negative cumulative price-difference settlement fees over the same four-month period. The Beijing-Tianjin-Jibei region has not yet initiated continuous spot settlement trials; hence, market transaction prices are calculated based on weighted average prices of comparable assets in moderately liquid M2L power transactions, ranging from RMB 370/MWh to RMB 400/MWh. This pricing level is markedly higher than the spot market transaction prices observed in most other provinces for renewable generation — particularly photovoltaic assets. Meanwhile, local mechanism pricing in this region fluctuates between RMB 320/MWh and RMB 360/MWh, creating a persistent price inversion against prevailing market prices.

By contrast, Shanghai has fully launched continuous spot market settlement operations. According to public trading data released by the Shanghai Power Trading Center in March and April 2026, daily spot market prices remained above RMB 420/MWh for approximately 90% of recorded trading days. As a result, Shanghai's unified wind and solar mechanism pricing of RMB 415.5/MWh also forms a price inversion relative to market levels. Notably, Shanghai's price-difference settlement fee has trended upward month-on-month, turning from negative to positive starting in March 2026.

5. The capacity pricing mechanism is expanding to include more types of generation-side entities, with the compensation depending on peak-serving capability

In January 2026, the NDRC and the NEA jointly issued the *Notice on Improving Generation-Side Capacity Pricing Mechanism*, also known as Document No. 114.[16] Based on existing capacity pricing mechanisms for the coal power generator and pumped-hydro storage,[x] the document set guidelines for provinces to refine capacity-pricing mechanisms and establish reliable capacity compensation mechanisms on the generation side.

For coal power generators, starting in 2026, the proportion of fixed costs recovered through capacity pricing will increase from “around 30% in most areas” (RMB 100/kW per year), according to Document No. 114, to “no less than 50%” (i.e., no less than RMB 165/kW per year). The specific proportion will be determined by provincial authorities based on local conditions.

For pumped-hydro storage projects, those commenced after the April 2021 release of Document No. 633, *Opinions on Further Improving the Pricing Mechanism for Pumped Hydro Storage*, will receive a province-based rather than a project-based capacity price.

Document No. 114 also clarifies that provincial authorities can establish capacity pricing mechanisms for natural gas power generator and grid-side stand-alone energy storage. The capacity-price level for grid-side stand-alone energy storage will be based on the local coal power capacity price standard, calculated as a certain proportion of peak capacity.

In addition to differentiated capacity pricing set by technology, Document No. 114 proposes the orderly establishment of a reliable capacity compensation mechanism for the generation side.[xi] Under the reliable capacity compensation mechanism, generation-side players of different technologies are to be uniformly compensated based on their reliable capacity. Provinces with suitable conditions may form capacity pricing through capacity markets and other means in due course.

---

x Power capacity prices are differentiated according to the corresponding entity, where “price” would be applied to generators and “fee” to consumers.

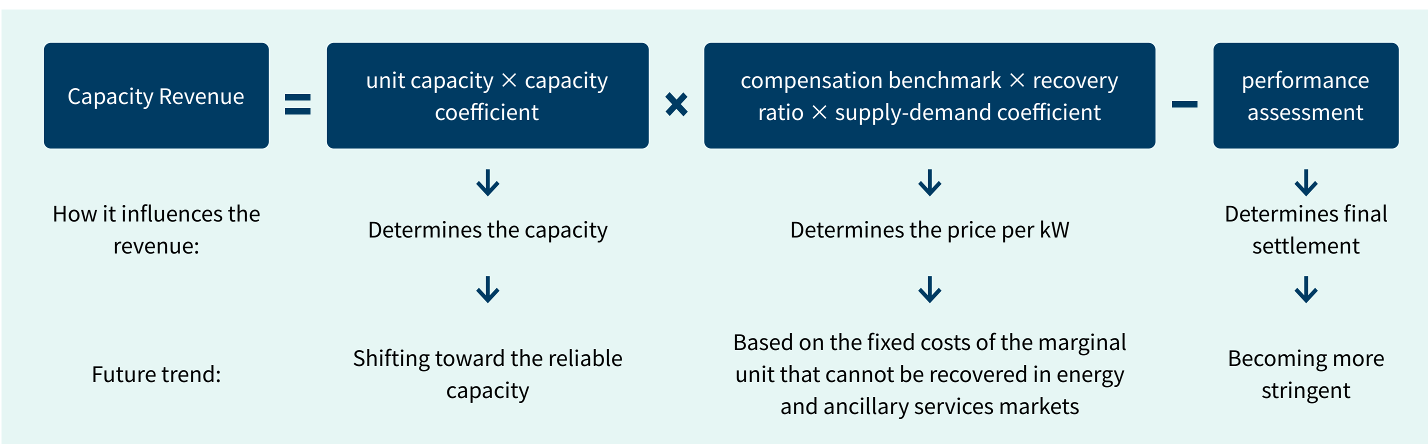
xi The reliable capacity refers to the capacity that a resource can continuously and reliably provide during periods of system peak demand.

Under a unified national framework, the differences in details regarding capacity calculation, unit price calculation, and performance assessment across different provinces will affect the actual capacity revenue level of operating entities

As of early April 2026, approximately 20 provinces had adjusted their capacity pricing mechanism or released a draft for comment. Consistent with the requirements of Document No. 114, the current adjustments to capacity pricing mechanisms in various regions can be divided into two categories. One is to continue designing the capacity pricing mechanism by technology type: directly adjusting the existing capacity price levels for coal and natural gas power generators or adding a new capacity pricing mechanism for grid-side stand-alone energy storage. Most provinces have adopted this method to adjust capacity price levels. The second approach integrates capacity pricing across generation-side technologies by defining eligible resource types, converting nameplate capacity into reliable capacity (or effective capacity in some provincial proposals), and applying a unified compensation standard based on reliable capacity.

For generation-side entities, regardless of technology and province, their capacity revenue can be broken down according to the structure shown in Exhibit 8. Unit capacity and capacity coefficient will jointly affect the actual peak-capacity level that the power generation entities (including grid-side stand-alone energy storage) can declare and be compensated for; benchmark price, recovery ratio, and supply-demand coefficient will jointly affect the price per kilowatt per year; and performance assessment will directly affect the actual settled capacity revenue.

Exhibit 8 **Factors determining generation-side entities' capacity revenue**



RMI Graphic. Source: RMI

Compared with provincial coal power capacity pricing practices in 2024–25, the latest round of reforms is expected to introduce greater regional differentiation in capacity pricing design. Differences in capacity calculation, compensation standards, and performance assessment will directly affect the capacity revenue available to generation-side resources. The following sections examine the key factors shown in Exhibit 9 and how they are evolving under Document No. 114. Exhibit 9 shows how various provinces are implementing the reforms.

Unit capacity: Capacity mechanisms are gradually moving beyond nameplate capacity toward reliable capacity (or "effective capacity" in some provincial proposals). Under the coal power capacity pricing mechanism implemented in 2024–25, most provinces used nameplate capacity to calculate capacity revenue. Under emerging unified generation-side capacity mechanisms in provinces like Gansu, Ningxia, and Qinghai, reliable capacity is generally defined as nameplate capacity times one minus plant self-consumption rate,[xii] and serves as the upper limit for capacity declarations. Similar approaches are being applied to non-coal resources, including grid-side stand-alone energy storage and concentrated solar power, with adjustments based on self-consumption rate.

Capacity coefficient: A capacity coefficient is increasingly used to convert different technologies into comparable peak-serving capacity. The coefficient is particularly relevant for resources with storage components or limited output duration, such as battery storage and concentrated solar power. In current provincial practice, the coefficient is typically calculated by dividing a resource's continuous full-power output duration by a locally defined reference duration that reflects system peak needs. The coefficient is capped at 1. Because coal and gas units can generally sustain full output for extended periods, their coefficient is assumed to be 1. This approach is primarily used for energy storage and, in Qinghai's draft proposal, concentrated solar power. Across current provincial designs, the reference duration ranges from 4 hours in Hebei to 10 hours in Hubei.

Compensation benchmark: The nationally unified fixed-cost benchmark remains the basis for capacity compensation. When the coal power capacity pricing mechanism was introduced in 2023, a benchmark fixed cost of RMB 330/kW-year was adopted nationwide. This benchmark continues to underpin most provincial capacity mechanisms. Looking ahead, Document No. 114 proposes that reliable capacity compensation should be based on the unrecovered fixed costs of marginal generation resources after energy and ancillary service market revenues are considered. As the costs of marginal resources differ across regions, compensation benchmarks may diverge over time.

Recovery ratio: Recovery ratios have generally increased, with some provinces reaching full cost recovery. In 2024–25, most provinces set recovery ratios at around 30%, while a smaller number adopted a 50% level. Under national policy, all provinces will increase recovery ratios to at least 50% from 2026 onward. Among provinces that have already completed adjustments, most have moved to 50%, while Sichuan and Tianjin have adopted 70%, and Yunnan, Jilin, and Gansu have targeted 100%. Because provincial authorities often use coal power capacity price as the benchmark for determining compensation levels for non-coal resources, coal power recovery ratios also influence compensation levels for other technologies. Over time, under a generation-side reliable-capacity compensation mechanism, the recovery ratio is expected to be incorporated with the compensation benchmark into a unified compensation standard applicable across resource types.

Supply-demand coefficient: Some provinces have introduced a capacity supply-demand coefficient to make compensation levels more responsive to local system conditions. The coefficient is generally calculated as the ratio of system demand to reliable capacity during the time of year when system net load is at its highest. Compensation levels increase when reliable capacity becomes relatively scarce and decline when supply is more ample. Gansu has already adopted this approach, while Qinghai and Ningxia have included similar provisions in draft policies.

Performance assessment: In some provinces, performance assessment requirements are becoming more stringent to ensure that resources receiving capacity compensation can reliably deliver their declared

xii Self-consumption rate refers to the energy used to support daily operation of the power plant over total generation of the power plant.

capacity. In 2024–25, most provinces followed the assessment framework set by *Notice on Establishing a Coal Power Capacity Pricing Mechanism*, which applies a 10% deduction to monthly capacity revenue after two violations, a 50% deduction after three violations, and a 100% deduction after four or more violations. Although most provinces continue to follow this framework, some have proposed stricter requirements as capacity mechanisms expand to cover more technologies. For example, Gansu applies a 50% deduction after the first violation and a 100% deduction after the second. These developments suggest that performance assessment is likely to play an increasingly important role in determining actual capacity revenue.

Exhibit 9 **Capacity-pricing breakdown in selected provinces (as of early April 2026)**

<table>
<tr><th>Province</th><th>Unit capacity</th><th>Reference duration (the number of hours in the denominator of capacity coefficient when converting non-thermal power units)</th><th>Compensation benchmark
(RMB/kW per year)</th><th>Recovery ratio</th><th>Supply-demand coefficient</th><th>Performance assessment</th></tr>
<tr><td>Gansu</td><td rowspan="3">Nameplate capacity times one minus plant power self-consumption rate</td><td>6</td><td rowspan="16">330</td><td>100%</td><td>0.8953</td><td>50% deduction after the first violation, 100% deduction after the second</td></tr>
<tr><td>Qinghai</td><td>4</td><td>50%</td><td>1.04</td><td>100% deduction after the first violation</td></tr>
<tr><td>Ningxia</td><td>6</td><td>50%</td><td>Not yet announced</td><td rowspan="14">10% deduction after the second violation, 50% after the third, and 100% deduction after the fourth</td></tr>
<tr><td>Hubei</td><td rowspan="13">Nameplate capacity in grid connection protocol</td><td>10</td><td>50%</td><td>-</td></tr>
<tr><td>Hebei</td><td>4</td><td>50%</td><td>-</td></tr>
<tr><td>Jilin</td><td>-</td><td>100%</td><td>-</td></tr>
<tr><td>Yunnan</td><td>-</td><td>100%</td><td>-</td></tr>
<tr><td>Sichuan</td><td>-</td><td>70%</td><td>-</td></tr>
<tr><td>Tianjin</td><td>-</td><td>70%</td><td>-</td></tr>
<tr><td>Guang-dong</td><td>-</td><td>50%</td><td>-</td></tr>
<tr><td>Shanxi</td><td>-</td><td>50%</td><td>-</td></tr>
<tr><td>Beijing</td><td>-</td><td>50%</td><td>-</td></tr>
<tr><td>Inner Mongolia</td><td>-</td><td>50%</td><td>-</td></tr>
<tr><td>Liaoning</td><td>-</td><td>50%</td><td>-</td></tr>
<tr><td>Zhejiang</td><td>-</td><td>50%</td><td>-</td></tr>
<tr><td>Anhui</td><td>-</td><td>50%</td><td>-</td></tr>
</table>

Note: Regular text represents provinces that have implemented adjustments; text in italics refers to the draft for comments released as of March 2026. Some regions (such as Liaoning and Qinghai) released new drafts for comment or published new policies after the second half of April, which are not reflected in this table or report. For instance, in Qinghai's new draft for comments, the denominator hours for energy storage capacity conversion increased from four hours (shown in the table) to eight hours, the compensation standard has been revised from 330 x 50% = 165 RMB/kW per year to 185 RMB/kW per year, and the supply-demand coefficient has changed from 1.04 to 0.92.

RMI Graphic. Source: Provincial development and reform commissions; RMI

Capacity revenue accounts for a growing share of generation revenue, while newer mechanisms increasingly reward peak-serving capability

In provinces that have adjusted capacity pricing levels, capacity revenue now accounts for a larger share of total generation revenue, particularly in parts of Northwest, Southwest, and Northeast China. Estimates suggest that in representative provinces such as Gansu, Yunnan, and Jilin, the share of capacity revenue has increased by around 10 percentage points and now exceeds 15% following the latest round of adjustments. By contrast, the share remains relatively low in coastal provinces, averaging around 6%–7%. Over the longer term, generation-side capacity compensation is expected to evolve from today's technology-specific fixed-cost recovery approach toward a unified mechanism that compensates resources based on their contribution to system reliability. Document No. 114 proposes gradually establishing a generation-side reliable capacity compensation mechanism once spot markets become fully operational. Under this framework, compensation would be based on reliable capacity and peak-serving capability, with a common set of principles applied across technologies.

This approach highlights two important shifts. First, compensation will increasingly be linked to a resource's ability to contribute during periods of peak demand, rather than to other attributes such as load-following capability or deep ramping capability. Second, compensation will become more technology-neutral, enabling a wider range of resources to participate under a unified framework. Over time, this approach could replace today's technology-specific capacity mechanisms and lay the foundation for market-based capacity pricing through capacity markets and other competitive mechanisms.

Several near-term trends are likely to emerge as provinces continue refining their capacity mechanisms. First, capacity compensation is expected to expand to cover grid-side stand-alone energy storage in more provinces. Second, provinces with high renewable penetration are likely to be among the first to adopt unified generation-side capacity mechanisms based on reliable capacity. Third, capacity valuation methodologies are expected to more accurately reflect peak-serving capability. Some existing approaches, such as those incorporating charging power or charging duration into storage capacity calculations, may be revised to better align with the principles established under Document No. 114. Finally, provinces with more mature spot markets are expected to lead the development of capacity markets, providing an early testing ground for market-based capacity price formation.

6. Capacity-based transmission and distribution tariffs represent a significant policy development, while system operation fees play a growing role in the overall electricity price structure

A capacity-based transmission and distribution tariffs model is established to promote local renewable energy consumption

In September 2025, the NDRC and the NEA jointly issued the *Notice on Improving Pricing Mechanisms to Promote Local Consumption of Renewable Power* (Document No. 1192).[17] The policy provides clearer pricing rules for local renewable energy consumption projects.[xiii]

Under Document No. 1192, eligible local renewable energy consumption projects — including direct green power connection, integrated source-grid-load-storage, and smart microgrid projects[xiv] — may pay transmission and distribution (T&D) tariffs based on their public grid connection capacity. For these projects, system operation fees and line-loss fees are temporarily charged based on grid imports, meaning the amount of electricity drawn from the public grid.[xv]

On specific pricing, Document No. 1192 specifies that local renewable energy consumption projects pay T&D tariffs based on project capacity, while grid imports are no longer charged volumetric T&D energy tariffs or system reserve fees. The capacity-based T&D tariffs calculation is built on the current two-part T&D tariff structure, which combines a capacity or demand charge with a volumetric charge based on electricity use.

Under the new approach, the capacity component follows the capacity or demand charge under the current two-part T&D tariff, while the volumetric component is converted into the following formula:

current energy T&D tariff at the applicable voltage level x average load factor of all 110 kV I&C users in the project-located province x 730 hours x public grid connection capacity

---

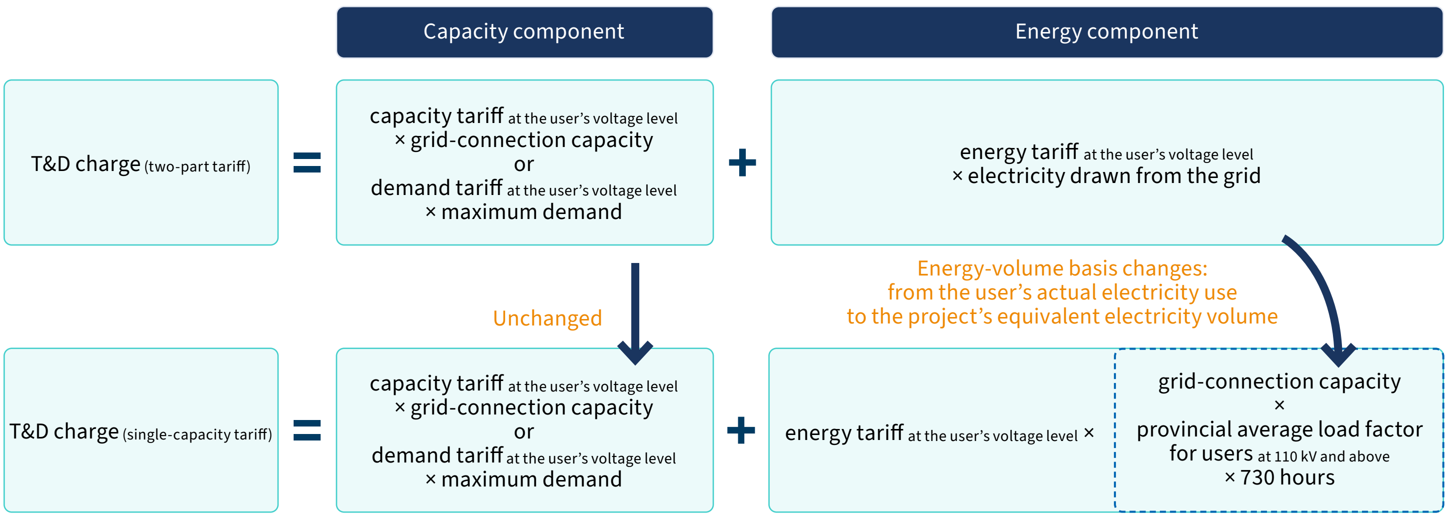
xiii A local renewable energy consumption project refers to a project in which nearby renewable generation supplies local load through a dedicated line.

xiv In this context, direct green power connection refers to renewable generation directly serving nearby users through a dedicated connection; integrated source-grid-load-storage refers to coordinated planning and operation of generation, grid connection, demand, and storage resources; and smart microgrids refer to local power systems that can coordinate distributed energy resources and interact with the public grid.

xv System operation fees refer to charges used to recover systemwide costs, such as capacity payments and other costs needed to maintain reliable power supply. Line-loss fees cover electricity losses that occur during transmission and distribution.

In this formula, 730 hours represents the approximate number of hours in a month. The average load factor reflects how intensively comparable users use their contracted or connected capacity over time. As a result, the volumetric component is no longer linked to the project's actual grid imports or electricity consumption. Instead, it becomes proportional to the project's public grid connection capacity, as shown in Exhibit 10. The document also preserves the option of using the current two-part tariff, which may better meet the needs of projects with higher supply reliability requirements.

Exhibit 10 **T&D tariff formula: Two-part tariff vs. single-capacity tariff**



RMI Graphic. Source: RMI

Under the new model, the T&D tariffs depend not only on their own capacity or demand profile, but also on the average transformer load factor of all 110 kV I&C users in the province. For local renewable energy consumption projects adopting capacity-based T&D tariffs, project planners may want to consider the economic impacts of regional load factor differences and potential changes over time while also accounting for grid connection capacity based on their own flexibility and self-balancing capability, to improve the load factor of grid connection capacity.

Renewable mechanism pricing and generation-side capacity pricing drive system operation fee adjustments and reshape end-user electricity cost structures

Since T&D tariffs entered the third regulatory period in June 2023, the electricity price structure for I&C users has changed significantly. The system operation fee was introduced as one of the five major components of I&C electricity prices.

Document No. 136, issued in early 2025, proposed the establishment of renewable sustainable development pricing mechanisms, often referred to as renewable mechanism pricing. This mechanism is designed to support the market entry of renewables while maintaining a certain level of revenue stability. Under the mechanism, renewable projects participate in the power market, and the difference between the mechanism price and the market price is settled afterward. These price difference settlement costs are being included in system operation fees as provincial policies are implemented and are shared with all I&C users.

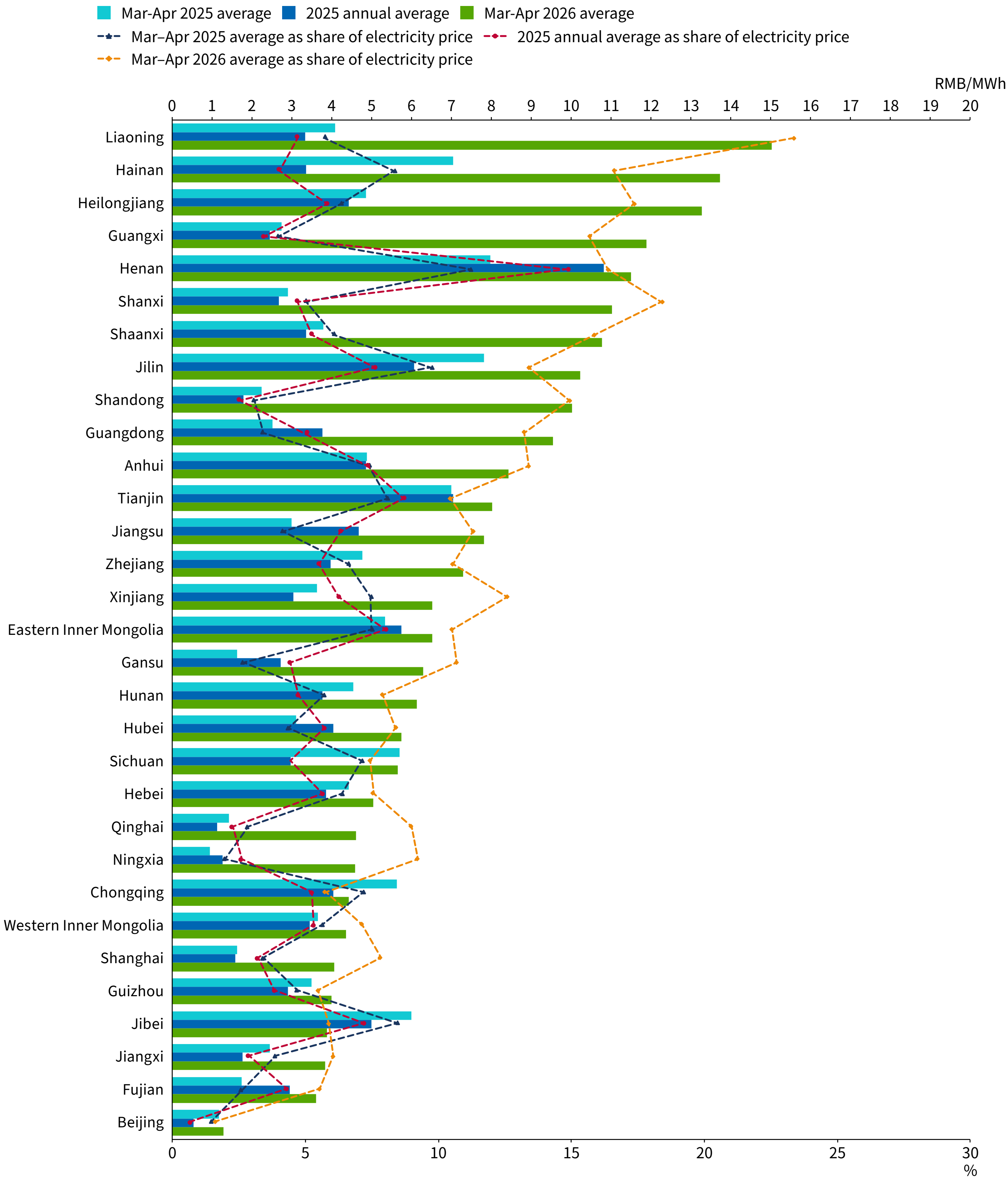
In 2025, system operation fees paid by I&C users were broadly unchanged from the previous year. Between 2024 and 2025, the average system operation fees across more than half of China's provincial grids changed less than RMB 0.01/kWh. Across provinces, system operation fees increased by only RMB 0.0066/kWh on average, indicating limited overall change.

However, from late 2025 to early 2026, as provinces began incorporating renewable mechanism price difference settlement costs into system operation fees and gradually raised coal power capacity price levels, system operation fees began to change visibly across provincial grids. Capacity prices refer to payments made to generation resources for providing reliable capacity, rather than for each unit of electricity generated.

This section uses system operation fee levels in March and April 2026 as the reference point after the price-level adjustment. As shown in Exhibit 11, system operation fees increased in most provincial grids. On average, system operation fees reached about RMB 0.0739/kWh in March–April 2026, up by about RMB 0.0373/kWh, or about 102%, from the 2025 full-year average of RMB 0.0366/kWh. Compared with the March–April 2025 average of RMB 0.0394/kWh, this represents an increase of about RMB 0.0345/kWh, or about 88%.

For 1–10 kV energy-only I&C users purchasing electricity through grid companies, the average share of system operation fees in electricity prices rose from 5.7% in March–April 2025 to 10.9% in March–April 2026. Energy-only users refer to users that pay T&D charges mainly on a per-kWh basis, rather than through a separate capacity or demand charge.

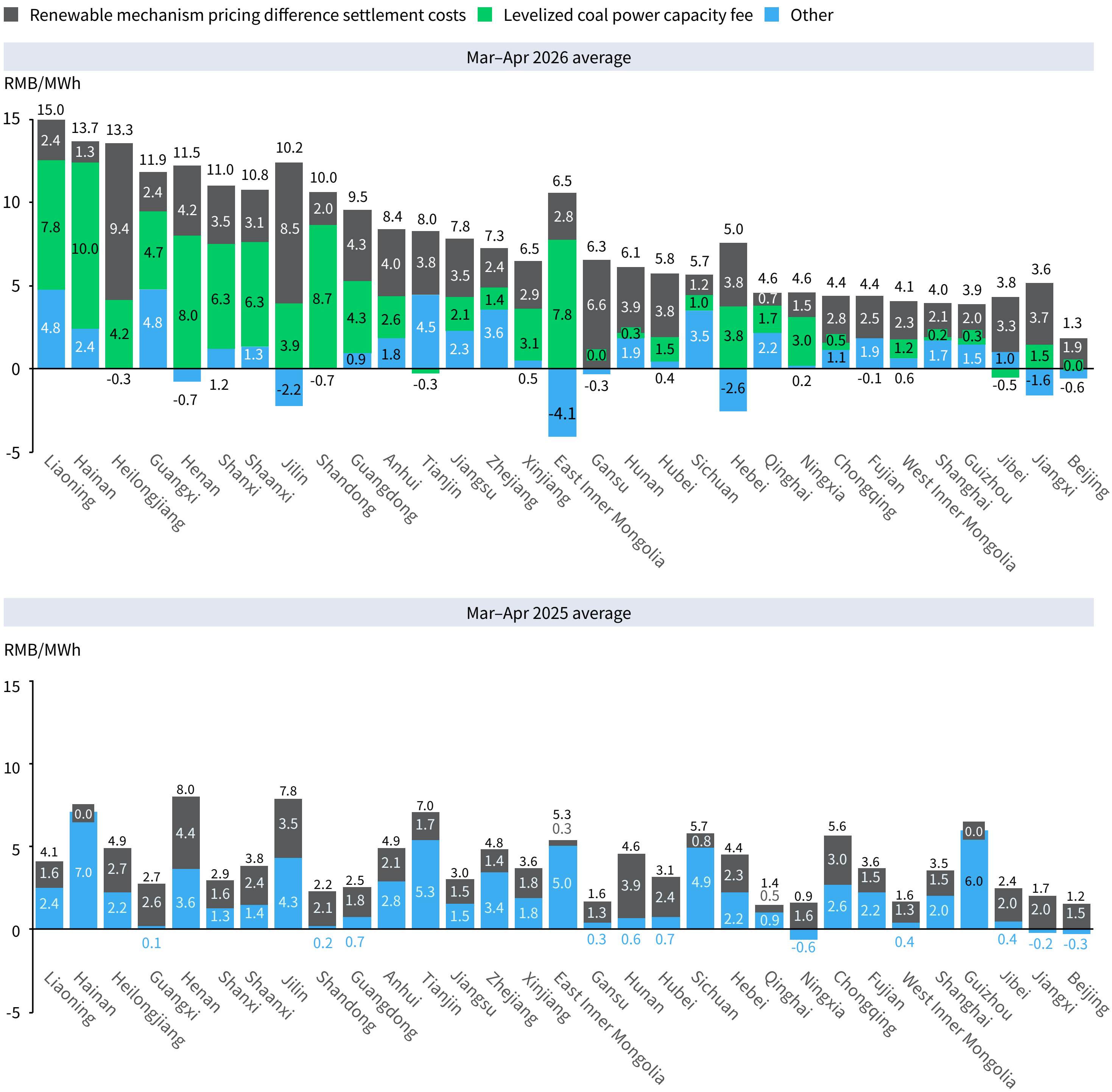
Exhibit 11 **Comparison by region of average system operation fees and their share of electricity prices**



RMI Graphic. Source: Provincial grid companies; RMI

At the provincial level, Liaoning, Hainan, Heilongjiang, Guangxi, Henan, Shanxi, Shaanxi, Jilin, and Shandong recorded relatively high system operation fees, with March–April 2026 averages exceeding RMB 0.10/kWh. Provinces with the largest increases in system operation fees included Liaoning, Guangxi, Heilongjiang, Shanxi, Shandong, Guangdong, Shaanxi, and Hainan — on average rising more than RMB 0.06 RMB/kWh year-on-year in March–April 2026 and by more than RMB 0.05/kWh compared with the 2025 full-year average.

Exhibit 12 **Composition of system operation fees by region**



RMI Graphic. Source: Provincial grid companies, RMI

In percentage terms, Ningxia, Shandong, Guangxi, Gansu, Shanxi, Guangdong, Liaoning, and Qinghai saw particularly large increases, all exceeding 200% (see Exhibit 12). As a share of electricity prices — using 1–10 kV energy-only I&C users purchasing electricity through grid companies as an example —system operation fees increased significantly across most provincial grids in 2026, rising from 3%–7.5% in 2025 to 6%–16% in 2026. In 17 provincial grids, the share exceeded 10%; in seven provincial grids, it exceeded 15%. Thus, system operation fees have become an important component of end-user electricity prices.

In the current system operation fee structure, price difference settlement costs and the levelized coal power capacity fee are the two largest components. Changes in these two fee components have directly driven the recent adjustment in system operation fees. It should be noted that both items also contribute to a decline in the energy price component. The rise in system operation fees and the decline in energy prices have largely offset each other, resulting in limited changes to end-user electricity prices. Taking 1–10 kV energy-only I&C users purchasing electricity through grid companies as an example, most provinces and regions (about 75%) saw lower electricity prices in March–April 2026 than in the same period of the previous year.

In the coming years, system operation fees will play an increasingly important role in overall electricity prices under the combined influence of renewable mechanism pricing and generation-side capacity pricing mechanisms.

Electricity volumes covered by both mechanisms are expected to grow. As generation-side capacity pricing is gradually implemented, more non-coal generation resources will be included in capacity pricing coverage and receive capacity revenue, increasing total generation-side capacity fees. At the same time, as bidding for mechanism-covered renewable electricity continues in subsequent years, more renewable generation will participate in price difference settlements, pushing up the overall scale of settlement costs.

At the same time, unit prices under both mechanisms may also gradually increase. For capacity prices, most provinces currently set the fixed-cost recovery ratio at 50%, equivalent to RMB 165/kW/ year, leaving some room for increase over the long term. At the same time, as capacity price standards increase, all else equal, the incremental capacity revenue of coal power units will replace part of their energy revenue; spot market clearing prices may therefore decline relatively, reducing renewables' capture prices in the spot market and widening the gap between capture prices and mechanism prices. This would further increase the unit price and total scale of price difference settlements.

Overall, the expansion of mechanism-covered electricity, broader capacity compensation coverage, higher capacity prices, and market price linkage effects will jointly drive adjustments in system operation fees. Some costs previously recovered through the energy market will shift to recovery through system operation fees. This trend reflects the rising importance of non-energy attributes of power, such as supply assurance and environmental value.

Changes in system operation fees may have differentiated impacts on emerging market entities:

- **Grid-side stand-alone energy storage faces higher costs**

  Under the rules clarified in Document No. 114, grid-side stand-alone energy storage is treated as a user when charging. Grid-side stand-alone storage refers to energy storage connected to the grid and operated as an independent market entity, rather than being paired with a specific renewable project or installed behind the meter of an end-user.

When charging, the electricity used by storage must pay applicable fees, including T&D tariffs and system operation fees. When discharging, T&D tariffs corresponding to the discharged electricity are refunded or reduced, but system operation fees are still charged based on the full charging volume. As system operation fees rise overall, and as fees in multiple regions have exceeded RMB 0.10/kWh, storage charging costs will increase significantly. This will directly compress the revenue space for storage projects and affect the investment payback period for stand-alone energy storage.

- **Local renewable energy consumption projects see improved economics**

  Under the current arrangements in Document No. 1192, local renewable energy consumption projects temporarily pay system operation fees and line loss fees based on grid imports, rather than following the same capacity-based pricing approach used for T&D tariffs. As a result, projects can reduce system operation fee payments by improving self-balancing and lowering grid imports.

  In regions where system operation fees have exceeded RMB 0.10/kWh, the price differential created by system operation fees will improve the relative economics of locally consumed renewable electricity and help cover the incremental costs of self-balancing in local renewable energy consumption projects.

  However, Document No. 1192 specifies that system operation fees are only temporarily calculated based on grid imports and will gradually transition toward approaches based on occupied capacity and other factors. Occupied capacity refers to the amount of grid capacity a project uses or reserves, even if it does not import electricity continuously. Market entities should therefore account for uncertainty from potential future adjustments.

7. Stand-alone energy storage economics improve as capacity pricing rolls out, while market-based TOU pricing reshapes industrial and commercial storage operations

By the end of 2025, China's cumulative installed novel energy storage capacity reached 136 GW/351 GWh, up 84% from the end of 2024 and continuing its rapid growth. In China, "novel energy storage" generally refers to non-pumped-hydro storage technologies, mainly battery energy storage systems.

According to the China Energy Storage Alliance, stand-alone storage accounts for around 58% of cumulative installations, variable renewable energy (VRE)-paired storage for around 33%, demand-side storage for around 8%, and thermal power-bundled-storage for frequency regulation for around 1.4%.[xvi]

National policy establishes capacity pricing mechanisms for stand-alone energy storage, with compensation tilted toward longer-duration projects

In January 2026, the NDRC and the NEA issued the *Notice on Improving Generation-Side Capacity Pricing Mechanisms* — Document No. 114. For the first time at the national level, the policy made clear that China would establish a capacity pricing mechanism for stand-alone storage and gradually establish a generation-side reliable capacity compensation mechanism.

Document No. 114 states that local governments may provide capacity price payments to grid-side stand-alone energy storage stations that support safe and reliable power system operation and are not used to meet mandatory VRE-paired storage requirements. The policy requires capacity price levels to be determined based on local coal power capacity price standards, together with factors such as discharge duration and contribution during peak load periods.

Building on capacity pricing mechanisms for thermal power, pumped hydro, and stand-alone storage, regions with continuously operating power spot markets may establish reliable capacity compensation mechanisms in due course. These mechanisms would compensate different resources' reliable capacity under unified principles. Regions with a high share of renewable installations and strong demand for reliable capacity may want to accelerate development of reliable capacity compensation mechanisms.

---

xvi Stand-alone storage refers to novel energy storage connected to the public grid and operated as an independent market entity. VRE-paired storage refers to storage paired with variable renewable energy projects, mainly wind and solar photovoltaic. Thermal power-bundled-storage for frequency regulation refers to storage paired with thermal units to provide fast grid-balancing services.

Document No. 114 essentially recognizes the system adequacy value of grid-side stand-alone energy storage — that is, its value in providing dependable capacity when the system is under stress. This may provide greater revenue visibility for stand-alone storage projects. It will also allow stand-alone storage to participate more fairly in power markets as an emerging entity, responding to price signals, providing system flexibility, and guiding more rational investment.

At the local level, Hubei, Hebei, Gansu, Qinghai, and Ningxia had already begun exploring capacity pricing mechanisms covering stand-alone storage before and after the release of Document No. 114, providing important references for other provinces.

Hubei and Hebei introduced capacity compensation payments specifically for grid-side stand-alone energy storage. Both provinces calculate capacity payments as the product of the capacity price standard and average available capacity. The formulas for monthly average available capacity in both provinces consider daily available discharge power, continuous discharge duration, and a capacity coefficient. Hebei also incorporates charging power and charging duration, reflecting an intent to guide storage to participate effectively in valley filling — charging during low-demand or low-price periods — and to support renewable integration.

Gansu, Qinghai, and Ningxia, which are among the provinces with the highest renewable penetration rates, have issued unified generation-side capacity compensation mechanisms in which multiple technologies participate together. These regions have high renewable shares and significant system flexibility pressure, creating strong demand for flexible resources such as novel energy storage.

Previously, capacity leasing under mandatory VRE-paired storage policies provided a source of capacity earnings for grid-side shared storage projects. Capacity leasing refers to a mechanism in which renewable developers lease storage capacity from stand-alone or shared storage projects to meet policy requirements. After Document No. 136 removed mandatory storage allocation requirements, this revenue source has gradually faded from newly built stand-alone storage projects. Against this backdrop, generation-side capacity pricing mechanisms have become an alternative incentive for continued storage investment and development.

In the pilot or draft-for-comment rules issued by Gansu, Qinghai, and Ningxia, capacity payments available to coal power, grid-side stand-alone storage, gas power, concentrated solar power, and other resources are determined under the formula: declared capacity (effective capacity) × capacity compensation standard × capacity supply-demand coefficient.[xvii] The capacity supply-demand coefficient reflects whether reliable capacity is relatively scarce or sufficient in the local power system.

From the funding perspective, all five provinces have established cost-allocation and pass-through mechanisms for capacity payments. The portion shared by all I&C users in the province is included in system operation fees, while the portion associated with exported electricity is determined through negotiation between generators and receiving provinces. These designs for grid-side stand-alone storage capacity pricing mechanisms and unified generation-side capacity compensation mechanisms are broadly consistent with the design logic of Document No. 114 and will provide an important reference for other provinces developing generation-side capacity mechanisms.

---

xvii Equivalent to unit capacity x capacity coefficient; capacity compensation standard is equivalent to compensation benchmark x recovery ratio (see Exhibit 8).

Although provinces follow similar mechanism designs, key parameter values create significant differences in storage capacity revenue. As shown in the formula above, capacity revenue for a given storage project is positively correlated with the capacity compensation standard and the capacity supply-demand coefficient and negatively correlated with the power plant self-consumption rate and the duration of system net load peaks. System net load peak duration refers to the length of periods when demand remains high after subtracting renewable generation.

The grid-side stand-alone storage capacity pricing mechanisms in Hebei and Hubei currently do not consider the capacity supply-demand coefficient or station self-consumption rate. Exhibit 13 presents the estimated capacity compensation revenue available to two-hour, four-hour, and six-hour grid-side stand-alone storage projects in five provinces. Due to differences in key parameters, annual capacity revenue for storage systems with the same power capacity and duration can differ by nearly threefold between Gansu and Hubei.

Stand-alone storage investors will find it useful to closely track the setting and changes of key parameters in each province's capacity mechanism. The capacity compensation standard will usually stay aligned with adjustments to coal power capacity price standards, while power plant self-consumption rate assumptions are likely to remain stable in the short term. Changes in the capacity supply-demand coefficient and system net load peak duration will be positively correlated with system load growth and negatively correlated with growth in reliable generation-side capacity.

Exhibit 13 **Comparison of maximum capacity revenue available to grid-side stand-alone energy storage with different durations across five provinces**

Mechanism category	Province	100 MW*2h	100 MW*4h	100 MW*6h	Capacity compensation standard (RMB/kW-year)	Capacity supply-demand coefficient	Power plant self-consumption rate	System net load peak duration / capacity coefficient denominator
Grid-side stand-alone energy storage capacity pricing mechanism	Hebei	450	900	1,350	100	N/A	N/A	4
	Hubei	297	594	891	165	N/A	N/A	10
Unified generation-side capacity compensation mechanism	Gansu	871	1,742	2,613	330	0.8953	1.74%	6
	Qinghai	692	1,384	1,384	165	1.04	10.39%	4
	Ningxia	438	875	1,313	165	Assumed 0.9	Assumed 1.74%	6

Note: The calculation of grid-side stand-alone energy storage capacity revenue assumes an ideal case in which stand-alone storage can fully charge and discharge once per day at maximum power and for the longest continuous duration. The calculation for the generation-side capacity compensation mechanism assumes an ideal case in which declared capacity or reliable (effective) capacity reaches its maximum value. Storage round-trip efficiency is assumed at 90%, with no assessment charges. Calculations for Qinghai and Ningxia are based on draft-for-comment documents issued in February 2026 and September 2025, respectively.

RMI Graphic. Source: Provincial development and reform commissions; RMI

Under current capacity pricing mechanism designs, the capacity coefficient used to calculate reliable, effective, or available storage capacity is linearly and positively correlated with continuous discharge duration. Therefore, for storage projects with the same rated power, capacity revenue is positively correlated with storage duration. This supports investment in longer-duration stand-alone storage.

However, both Gansu and Qinghai set the maximum capacity coefficient at 1. This means the positive relationship between storage duration and capacity revenue applies only when storage duration is no longer than the duration of the system net load peak. In addition, the current method of using a duration-based capacity coefficient may shift to more dynamic algorithms in the future.

Market-based TOU price formation is reshaping industrial and commercial storage operations, making diversified revenue models a key transition pathway

Based on projects already in operation or under construction, I&C storage revenue models remain centered on retail TOU price spread arbitrage and are still dominated by the energy management contract (EMC) model. Under this model, a third-party investor typically invests in, builds, and operates the storage system for an I&C user. Storage charges when retail electricity prices are low and discharges, or reduces grid purchases, when prices are high. The investor captures the price spread and then pays the user rent or shares part of the savings. Because users usually do not directly participate in dispatch decisions, EMC-based storage systems are less involved in demand management or other more advanced applications, leaving the revenue structure relatively simple. Self-invested and self-built projects may capture some demand management benefits, but project design and revenue estimates still rely primarily on TOU spread arbitrage.

This operating logic is being reshaped as TOU price formation shifts from administrative setting to market-based formation. In December 2025, the NDRC and the NEA issued the *Basic Rules for the Medium- to Long-Term Power Marke*t — Document No. 1656 — effective March 1, 2026. The rules state that M2L transactions should become more market-based and that the government will no longer uniformly specify fixed peak, shoulder, and valley periods, or floating ratios for users participating in the market.[xviii]

M2L transaction prices form the core cost basis for retail electricity prices. As their time-segmented price structure is passed through to end-users through wholesale-to-retail price pass-through or retail contract terms, the price spreads available to I&C storage will increasingly depend on market-formed M2L and spot price signals. As a result, I&C storage revenue logic is shifting from relatively certain arbitrage based on preset TOU periods to more dynamic operation based on market price signals.

Different retail price formation mechanisms across regions will directly affect the revenues and operating strategies of storage projects. As discussed in the retail section of Section 3, after the removal of administrative TOU arrangements on the wholesale side, provinces have adopted differentiated pathways for retail-side coordination, further affecting I&C storage project revenue and operations. Overall, wholesale-to-retail price pass-through is the long-term trend for retail price formation. However, during the transition period, regions have developed different implementation pathways based on local power system characteristics, market maturity, and existing storage scale.

xviii Shoulder periods refer to intermediate-price periods between peak and valley hours.

Current retail TOU price formation mechanisms can be broadly divided into two types. In the first type, the wholesale market passes only the average transaction price through to the retail side, while the retail peak-valley price curve can still be shaped through administrative requirements or voluntary negotiation. Examples include Shandong, Guangdong, and Jiangsu. This model provides a transition buffer for existing I&C storage projects by preserving some room to negotiate peak-valley periods and price spreads. In the second type, the wholesale market directly passes through the time-segmented price curve to the retail side and sets explicit requirements for how different wholesale transaction products are reflected in retail prices. South Hebei is one example. This model creates a more direct linkage between wholesale and retail TOU price signals and accelerates the formation of market-based TOU pricing.

These different pass-through models create different levels of spread certainty and volatility. Under average-price pass-through, retail-side arrangements change relatively little from the administrative TOU period. Users and retailers can still agree on peak-valley periods and price adjustment ratios in retail contracts, allowing storage projects to continue operating under relatively predictable spreads. By contrast, under time-segmented price pass-through, retail TOU prices are formed from the weighted average of multiple wholesale transaction prices. At present, M2L transaction prices often carry a relatively large weight, while spot prices account for a smaller share. However, current data shows that peak-valley spreads in both M2L and spot transactions are generally narrower than those under administrative TOU pricing.

Time-segmented spot average price spreads in typical provinces are concentrated in the range of RMB 0.1–0.5/kWh, while M2L spreads are often smaller. After different wholesale products are weighted into retail prices, the resulting spreads are likely to be significantly lower than those under administrative TOU pricing, which were commonly over RMB 0.5/kWh. As a result, I&C storage arbitrage space is narrowing, and project revenues are trending down. Storage can no longer rely on preset peak and valley periods for stable arbitrage; instead, it needs to adjust charging and discharging strategies dynamically based on M2L transaction outcomes and spot market price signals.

For I&C storage investors, project economics will increasingly depend on selecting both markets with sufficient TOU spread potential and users with strong operational flexibility. On market selection, investors need to assess whether local rules still preserve or reconstruct retail TOU spreads, including TOU coefficient settings, wholesale-to-retail pass-through approaches, and contract flexibility. They also need to evaluate actual market outcomes, including the level and stability of realized spreads. On user selection, even in markets with sufficient spread potential, project returns depend on whether users are willing and able to sign TOU retail packages with meaningful spreads and adjust operations accordingly. Users with continuous and stable loads, such as data centers, semiconductor manufacturers, and paper manufacturers, usually prefer higher price certainty and may choose packages with a larger fixed-price component. Users with more adjustable production schedules and more flexible loads, such as commercial buildings and equipment manufacturers, may be better positioned to coordinate operations with storage charging and discharging strategies.

As arbitrage space narrows, I&C storage will need to move from single price spread arbitrage toward more diversified revenue models. First, storage can work with retailers to optimize user-side load curves, reduce imbalance volumes and related assessment costs, and create indirect settlement benefits. In regions with strict deviation assessment for M2L contract execution, storage can serve as a hedging tool by responding quickly when actual consumption deviates from contracted volumes, reducing deviation charges, and creating room for revenue-sharing among users, retailers, and storage operators.

Second, storage can support user-side energy management by reducing maximum demand through peak shaving and valley filling, thereby lowering basic electricity fees under the two-part tariff. Although this revenue stream is limited in scale, it can provide an important supplement as TOU spreads narrow.

In more advanced models, storage can be aggregated with flexible loads into new market entities such as virtual power plants (VPPs) and participate directly in power markets. Under this model, the user side is no longer only a passive price taker. Instead, users can actively leverage the flexibility of load and storage to formulate bidding strategies, respond to market signals, and capture value from power market participation.

8. Generation-type virtual power plants are becoming a key route for distributed renewables to enter power markets

In April 2025, the NDRC and the NEA issued the *Guiding Opinions on Accelerating the Development of Virtual Power Plants*,[18] defining a virtual power plant (VPP) as a market entity that aggregates distributed resources — including distributed generation, flexible load, and energy storage — to participate in system optimization and electricity market transactions. Since then, provinces have released implementation rules that generally classify VPPs into two categories: load-type VPPs and generation-type VPPs.

Load-type VPPs mainly aggregate flexible demand-side loads, behind-the-meter storage, and EV charging and battery swapping infrastructure, and appear to the grid as load. In *2025 China Power Market Outlook: 10 Key Trends for Market Players*, we focused on load-type VPPs. Unlike the traditional demand-side model, which usually submits volume only and not price, load-type VPPs can generally participate in the spot energy market through volume-and-price bidding. This allows them to respond to price signals, reshape aggregated load profiles, lower procurement costs, and share savings with end-users. As spot market development accelerates across China, load-type VPPs have begun routinely participating in market trading in provinces such as Shanxi, Shandong, Hubei, and Gansu.

Generation-type VPPs mainly aggregate resources such as distributed solar photovoltaics (PV), distributed wind, and storage, and appear to the grid as generation. In some provinces, they are further classified into aggregation units for distributed generation and distributed storage. The emergence of generation-type VPPs is closely linked to Document No. 136,[19] which requires renewable electricity delivered to the grid to participate in market transactions. However, many small and geographically dispersed projects do not have the capability to trade independently. Aggregating these assets into a VPP and having a professional operator trade on their behalf has therefore become a practical route to market entry and is opening new commercialization opportunities for VPPs.

Distributed renewables are required to trade through spot markets, and aggregation through generation-type VPPs offers greater arbitrage potential

Provincial market-entry schemes for distributed renewables largely follow the design principles of Document No. 136 and typically offer three routes for distributed renewables to participate in spot markets on the generation side: (1) independent volume-and-price bidding, (2) participation through aggregation, and (3) participation as price takers. Considering both access requirements and the range of eligible power markets, aggregation often offers a comparative advantage for distributed renewable owners.

The three pathways involve progressively lower technical requirements for access. Based on rules in Guangdong, Shandong, and Shanxi, independent volume-and-price bidding has the highest entry threshold: projects must meet dispatch requirements such as active power control and the ability to follow scheduled generation curves. Following the aggregation pathway, if the generation-type VPP formed by aggregating the projects meets these requirements, the portfolio can bid both volume and price in the spot market. If these requirements are not met, distributed renewables can participate only as price takers.

In terms of eligible power markets, both independent volume-and-price bidding and aggregation through a generation-type VPP can participate in multiple power market products across different time horizons, including the M2L market as well as the day-ahead and real-time spot markets. This allows distributed renewables to rebalance positions across trading windows, reduce imbalance exposure, and expand price arbitrage opportunities (see Exhibit 14). Under these two models, distributed renewables are managed in ways similar to utility-scale renewables. By contrast, distributed renewables that participate as price takers cannot enter M2L transactions, including green power trading. Because these projects lack generation forecasting and autonomous trading capability, the power dispatch center typically provides forecast generation curves on their behalf for spot market clearing, and settlement is based on actual delivered electricity and the node's TOU real-time spot price.

Exhibit 14 **Participation pathways for distributed renewables in the energy market in selected provinces**

Province	Participation pathway		Spot market		Participation in M2L market
			Day-ahead	Real-time	
Guangdong	Independent volume-and-price bidding		Participates through volume-and-price bidding		Voluntary
	Aggregated via a generation-side VPP				
	Price taker		Cannot participate	Settled based on delivered volume and node TOU price	Cannot participate
Shandong	Independent volume-and-price bidding		Full volume included in day-ahead reliability unit commitment; voluntary participation in day-ahead economic clearing	Full-volume participation; temporarily cleared based on day-ahead bids	Voluntary
	Aggregated via a VPP "distributed generation aggregation unit"				
	Price taker		Cannot participate	Settled based on delivered volume and node TOU price	Cannot participate
Shanxi	Independent volume-and-price bidding		Participates through volume-and-price bidding		Participates under the utility-scale renewables trading model
	Means of aggregation	Distributed generation VPP			
		Source-load (hybrid) VPP	Volume-and-price bidding in day-ahead market; may choose to participate in intraday/real-time market		In principle, does not participate
	Price taker		Cannot participate	Settled based on delivered volume and node TOU price	Cannot participate

Note: In Shanxi, "source-load" (hybrid) VPPs refer to listed operators that, in line with integrated source-grid-load-storage projects, green power industrial parks, microgrids, and similar programs, aggregate renewables, load, and storage and register them as a single VPP. Guangdong's VPP market-entry scheme differs from the Southern Power Grid regional market approach; the exhibit reflects Guangdong's rules.

RMI Graphic. Source: Provincial power exchange centers; RMI

Distributed renewable owners can weigh the retrofit cost of each pathway against expected revenues to choose the most suitable route to market. Both independent volume-and-price bidding and aggregation through a generation-type VPP typically require distributed renewables to meet the “four capabilities” of being observable, measurable, adjustable, and controllable, so that they can be dispatched by the system operator or controlled by the VPP operator. Available estimates suggest that the hardware cost of a four-capability retrofit package for commercial and industrial distributed PV is typically RMB 10,000–30,000, increasing total up-front investment by about 1%.[20]

In addition, the independent pathway requires owners to build in-house trading capability, which raises both cost and operational complexity. Under the aggregation pathway, projects can rely on the VPP operator’s trading capability and share in the additional value created by portfolio participation, for example when paired with storage. However, provincial progress on VPP market entry remains uneven. Many generation-type VPPs are still at the qualification and platform integration stage and have not yet scaled. Owners will benefit from tracking real-world cases and revenue outcomes closely and negotiating key terms in agency contracts with VPP operators, including settlement pricing, benefit-sharing ratios, and service fees.

Distributed renewables aggregators are expected to transition into generation-type VPPs in some provinces

Before Document No. 136 was issued, Jiangsu, Zhejiang, and Anhui piloted aggregated trading of distributed green power, under which distributed renewables aggregators represented distributed projects in green power trading. This model lowered barriers to market entry and expanded the supply of provincial green power. At the time, spot markets in these provinces were not yet in continuous operation, and distributed renewables could still be purchased by the grid under guaranteed volumes and prices. In practice, aggregators and retailers (or wholesale users directly participating in the market) typically priced the energy component at the local coal power benchmark price, while pricing the environmental attribute with reference to green power trading outcomes for utility-scale renewables. If contracted green power volumes did not exceed the delivered electricity of the aggregated projects, the volumes were not subject to imbalance penalties; any remaining electricity was settled at the guaranteed purchase price. Accordingly, the aggregator’s role was relatively light-touch — focused mainly on monetizing environmental attributes — and generally did not require dispatch or control capability over the aggregated assets.

Issuance of Document No. 136 means distributed renewables aggregators need to evolve into generation-type VPPs and take on additional roles beyond green power trading to maintain stable agency relationships with customers:

- **Provide end-to-end agency services for market participation.** Under trading rules in most provinces, the on-grid electricity of distributed renewables may be partially covered by mechanism pricing, while volumes beyond the mechanism portion can choose to participate in the M2L market (including green power trading) and must participate in the spot market. If a legacy aggregator transforms into a generation-type VPP and can represent distributed renewables across multiple market products, it can provide integrated services and maximize portfolio value.

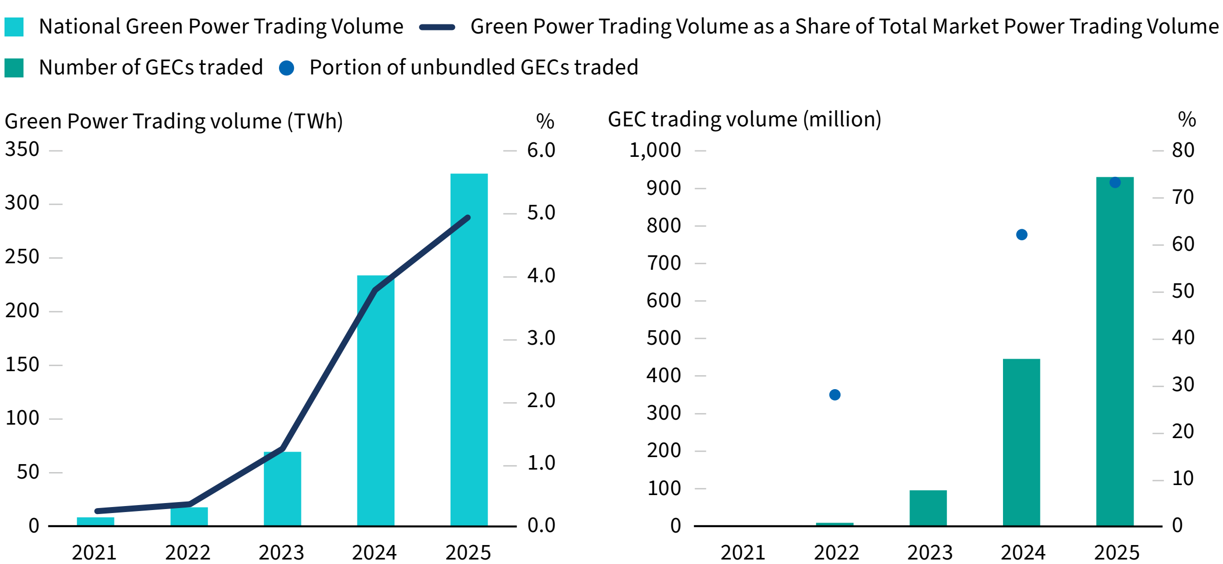
- **Build dispatch and control capability over aggregated distributed renewables.** Unlike earlier aggregators that mainly helped customers monetize environmental attributes, generation-type VPPs must connect to dispatch automation systems and be able to receive and execute dispatch instructions in real time. This requires real-time control over aggregated assets and, in practice, offering four-capability retrofit services to distributed renewable customers.

Under the new model, distributed project networks and aggregated trading capability will become central to competitiveness for generation-type VPP operators. Among the first batch of generation-type VPPs participating in market trading in Guangdong, parent companies' core businesses typically include distributed renewables development, operations and maintenance (O&M), and integrated energy services — helping them build extensive resource networks and accumulate experience in managing distributed portfolios. Many also hold electricity retailer licenses, providing trading capability and hands-on market experience. Overall, companies with capabilities across distributed renewables O&M, electricity retail, and integrated energy services are well positioned to capture early-mover advantages in generation-type VPPs. They can also explore value-added services for distributed renewable owners, including load optimization, outsourced energy management, and even carbon management.

9. Green power supply-demand balance remains relatively loose, while application scenarios are expanding, driving demand for green energy certificates

Green power and trading in green energy certificates (GECs) continued to expand rapidly in 2025, while environmental attribute prices remained relatively subdued. Green power trading reached 328.5 terawatt-hours (TWh), up 38.3% year-on-year,[21] and GEC transactions totaled 930 million certificates, more than double that in 2024. Unbundled GECs remained the dominant product, accounting for roughly 73% of total transactions (see Exhibit 15).[22] Environmental attribute prices remained modest across both the State Grid and China Southern Power Grid regions. In Jiangsu, the average green power premium fell to RMB 14.86/MWh in 2025, down from RMB 24.92/MWh in 2024.[23] In Guangdong, the average premium rose to around RMB 11/MWh,[24] compared with RMB 8.8/MWh a year earlier.[25] Nationally, the weighted average GEC price was RMB 4.39 per certificate between April and December 2025, below the 2024 average of RMB 5.59.[26] Prices strengthened noticeably in the second half of 2025, however, with average GEC prices rising by roughly 90% compared with the first half.[27]

Exhibit 15 **Green power and GEC trading volumes, 2021–2025**



RMI Graphic. Source: NEA; Beijing Power Exchange Center; RMI

Green power trading rules continue to evolve; green power supply is expected to remain ample over the next two years

As the market for multiyear green power transactions develop, companies with long-term renewable electricity needs are gaining more options to secure supply and manage price risk. Since late 2024, the regulatory framework for multiyear trading has been refined through a series of rule updates. In October 2025, revised green power trading rules gave multiyear transactions the highest priority within the green power market,[28] expanded opportunities to execute multiyear deals through annual and monthly trading cycles, and opened additional contracting windows. Updated M2L market rules further encouraged participation in multiyear green power transactions and called for the establishment of a more regular trading mechanism.[29] Market activity has already begun to pick up. Cumulative trading volume under multiyear green power purchase agreements has reached 60 TWh.[30] As market rules continue to evolve, more standardized contracts, greater transaction flexibility, and improved pricing arrangements are likely to support continued growth in multiyear green power trading.

Green power trading is becoming more closely integrated with other M2L market products. Green power transactions are increasingly aligned with time-segmented M2L trading mechanisms, with the energy portion traded either on a time-segmented basis or through load-curve-based transactions. Provinces including Zhejiang, Anhui, Henan, Hubei, and Sichuan organize transactions across 24 hourly periods, while regions such as the North Hebei grid adopt a five-period structure consisting of sharp peak, peak, shoulder, valley, and deep valley periods. Jiangxi and several other regions have further increased temporal granularity by refining transactions into 48 settlement periods. Meanwhile, regions such as Beijing and Tianjin still require participants to submit electricity volumes hourly, while continuing to apply a single uniform electricity price across the entire day.

Provincial 2026 M2L trading plans point to three distinct approaches to pricing green environmental attributes (see Exhibit 16). Some provinces, including Beijing, East Inner Mongolia, and Jiangsu, use prevailing GEC prices as a reference for green power pricing. Others, such as West Inner Mongolia and Zhejiang, apply explicit price caps. A third group, including Anhui, Shandong, and Henan, leaves pricing entirely to the market without formal guidance. As the market matures, pricing is likely to become increasingly market-driven, with fewer administrative constraints on environmental attribute values.

Exhibit 16 **Approaches to pricing guidance for environmental attributes in green power trading across selected provincial grids**

Pricing approach	Provincial grid	Mechanism
Referencing average GEC prices	Beijing	Environmental attributes pricing references the average transaction price of unsubsidized GECs in the State Grid region during the previous settlement cycle.
	East Inner Mongolia	Environmental attributes are determined based on supply-demand conditions in the GEC market.
	Jiangsu	Environmental attributes reference the average GEC transaction price on the Beijing Power Exchange Center prior to trading.
Setting explicit price caps	West Inner Mongolia	Environmental attributes must be no lower than RMB 1/MWh and no higher than RMB 31.5/MWh.
	Zhejiang	Prices must range between RMB 0.01/GEC and RMB 50/GEC.
No explicit pricing guidance	Anhui	No price cap, but transaction price must be above zero.
	Shandong	No price caps or indicative pricing guidance for GECs.
	Henan	No price caps or designated pricing guidance.

RMI Graphic. Source: Provincial green power trading implementation plans; RMI

Although mechanism pricing power volume is not eligible for green power trading, green power supply is expected to remain ample through 2027. To assess the impact of mechanism pricing power volume on market supply, we modeled green power supply and demand in Jiangsu, Guangdong, Shandong, and Shanxi for 2025–27 using provincial mechanism pricing rules, auction results, and renewable capacity growth forecasts. Transmission constraints were not considered in the analysis. Across all four provinces, the green power supply-demand ratio is projected to increase steadily between 2025 and 2027 and remain above 1 throughout the period. This suggests that supply will continue to exceed demand through 2027, and the market will become increasingly well supplied.

The favorable supply outlook is driven by two factors. First, renewable capacity continues to grow briskly. Although growth is expected to slow from 2025 levels, annual additions across the four provinces are still projected to increase by 15%–20% in 2026–27, providing a steady source of new green power supply. Second, mechanism pricing power volume allocated to new projects remains limited . Although new projects are generally allowed to nominate 70%–90% of their output for the mechanism (see Exhibit 17), total auction volumes are capped. As a result, the actual share of mechanism pricing power volume is much lower for new projects than for existing projects. This leaves a significant portion of new renewable generation to be sold directly into the market, adding to available green power supply. Given these market fundamentals, upward pressure on green power premiums is likely to remain limited.

Exhibit 17 **Maximum eligible mechanism pricing power volume share for individual projects and provincial mechanism volume in Jiangsu, Guangdong, Shandong, and Shanxi**

Province	Maximum eligible share for individual projects		Provincial mechanism volume as a share of renewable on-grid generation	
Province	existing projects	2025–2026 incremental projects	existing projects	2025–2026 incremental projects
Jiangsu	Residential distributed PV and poverty alleviation PV projects: **100%**; all other projects: **90%**	**90%**	**90%**	**49%**
Guangdong	Projects below 110 kV commissioned before Dec. 31, 2024: **100%**; utility-scale projects at or above 110 kV commissioned from Jan. 1, 2025, onward: **50%**; other projects: 70%	Distributed PV projects below 110 kV: **80%;** other distributed PV projects: **70%**	**79%**	**12%**
Shandong	Poverty alleviation PV: **100%;** residential PV owned by individuals commissioned before Dec. 31, 2024: **100%;** residential PV commissioned between Jan. 1 and May 31, 2025 : **85%;** large commercial and industrial projects: 0% other existing projects: **80%**	Wind: **70%** Solar: **80%**	**76%**	**56%**
Shanxi	Utility-scale parity projects: **85%**	**80%**	**89%**	**57%**

RMI Graphic. Source: Provincial development and reform commissions; RMI

Green energy certificate life-cycle management is improving, with its applications expanding across a broader range of use cases.

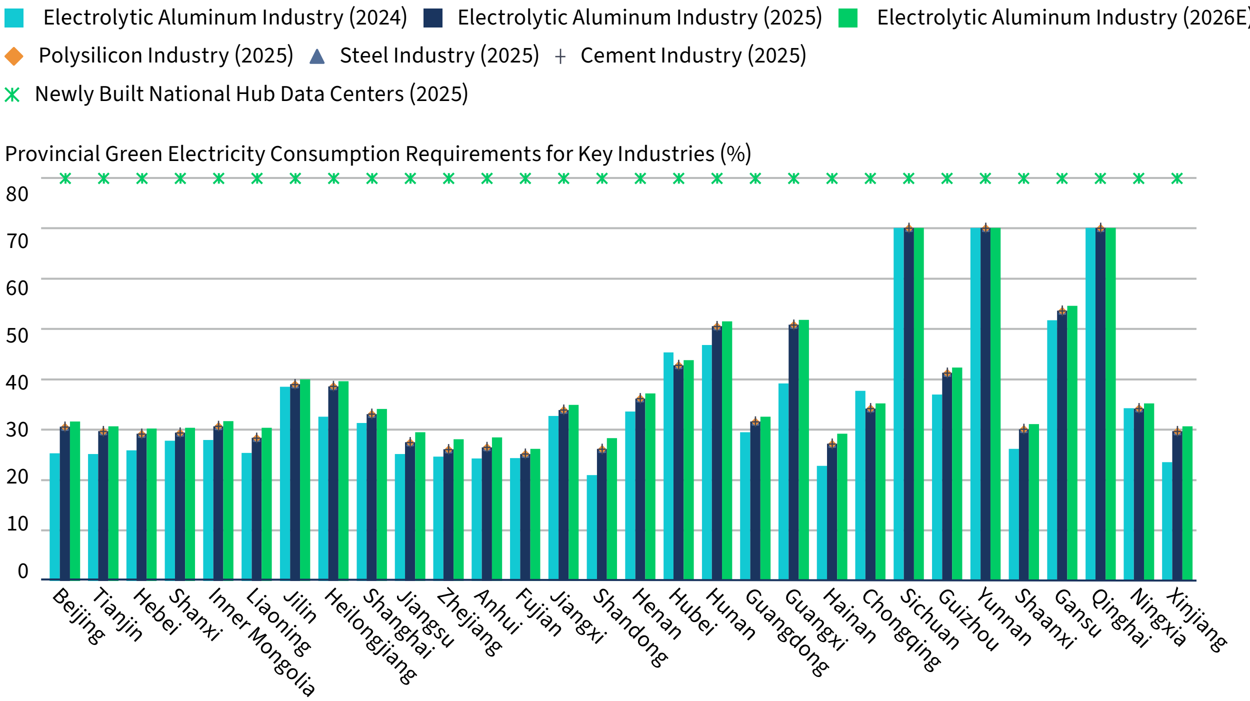
GEC prices increasingly reflect differences in certificate freshness. In 2025, GECs associated with electricity generated in the same year traded at an average price of RMB 5.57/certificate, compared with RMB 2.12 for certificates linked to 2024 generation. Older-vintage GECs associated with electricity generated in 2023 and earlier traded at much lower levels, averaging just RMB 0.72/certificate.[31] This price gap is largely driven by temporal matching requirements in certain green electricity accounting and claims frameworks, where the generation year of the underlying electricity must align with the year in which the environmental attributes are used. In January 2026, new GEC implementation rules strengthened life-cycle management across issuance, transfer, and retirement, while formally introducing a two-year validity period. The rules also clarified that GECs retired for green electricity consumption claims must be linked to electricity generated in the same calendar year. As temporal matching requirements become more important, fresh GECs are likely to retain a clear pricing premium.

The allocation of GECs held in provincial accounts remains uncertain, as no province has yet released a finalized distribution scheme. Under Document No. 136, mechanism pricing power volume is not eligible for additional GEC revenues, and the associated GECs are transferred into provincial accounts. How these certificates will ultimately be distributed will depend on province-specific allocation rules that have yet to be finalized.

Over the next few years, GEC demand is expected to be driven by stricter green electricity consumption requirements for energy-intensive industries and increasing pressure from both domestic and multinational companies to decarbonize their supply chains. At the same time, green electricity consumption is spreading across a broader range of buyers and applications. Together, these trends are expected to support continued growth in GEC demand.

Green electricity consumption requirements are expanding across a growing number of industries, and minimum thresholds are expected to increase. As a result, more companies will need to rely on renewable electricity procurement and energy management strategies to meet compliance obligations. In 2025, China's electrolytic aluminum industry moved from monitoring to mandatory compliance. Provincial requirements for green electricity consumption ranged from 25.2% to 70%, and nearly 90% of provinces set higher indicative targets for 2026 than their mandatory requirements in 2025. Steel, polysilicon, cement, and national hub data centers have already been brought into the monitoring framework. Among them, all newly built national hub data centers are subject to an 80% green electricity consumption requirement (see Exhibit 18). Policy signals suggest that the scope could broaden. In March 2025, new guidance jointly issued by five government agencies called for faster adoption of green electricity across industries including steel, non-ferrous metals, building materials, petrochemicals, chemicals, and data centers. Additional sectors are likely to be brought into future monitoring and compliance frameworks.

Exhibit 18 **Green electricity consumption requirements for key industries, by province, 2024–26**



RMI Graphic. Source: NDRC; RMI

Supply chain requirements are becoming a major driver of green electricity demand in China. Many multinational companies, including Nike and Apple, have identified 2030 as a milestone in their decarbonization strategies. As these companies work to reduce emissions across their value chains, suppliers in China are facing growing pressure to increase their use of renewable electricity. A similar trend is emerging among domestic companies. China's central state-owned enterprises are increasingly incorporating low-carbon criteria into procurement and supplier management processes, using their purchasing power to encourage cleaner energy use throughout their supply chains. Recent guidance from SASAC (State-Owned Assets Supervision and Administration Commission under the State Council) calls on central state-owned enterprises to strengthen supplier carbon management, promote cleaner production practices, and increase the use of renewable electricity across supplier networks.[32] The guidance also introduces a dynamic supplier evaluation system linked to environmental performance. Suppliers with strong low-carbon performance may gain a competitive advantage in procurement decisions, while those that fail to improve may have fewer business opportunities. Together, these developments are likely to increase demand for green electricity and GECs across industrial supply chains.

10. Vehicle-to-grid pilots continue to expand, and provinces begin introducing discharge pricing mechanisms

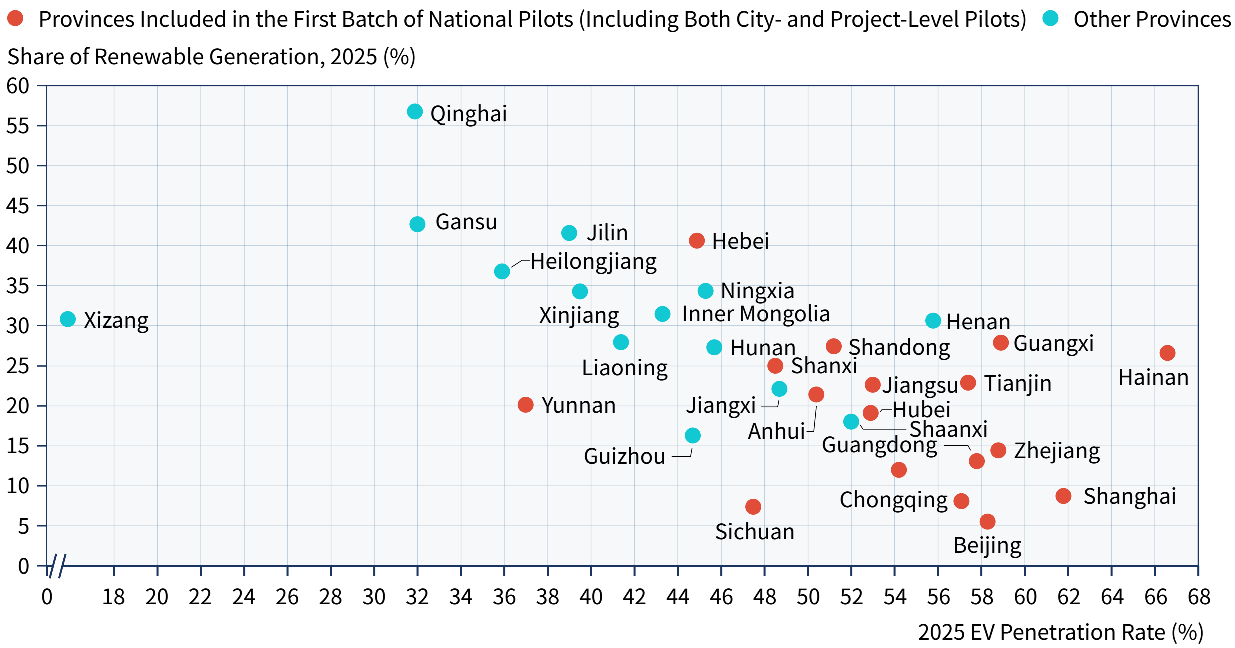
In April 2025, the NDRC and several other government agencies launched the country's first batch of vehicle-grid integration pilots, covering nine cities — including Guangzhou, Changzhou, and Shanghai — and 30 pilot projects.[33] Vehicle-grid integration encompasses both smart charging and vehicle-to-grid (V2G) applications. Our 2025 market outlook report focused on the rollout of TOU pricing for residential EV charging and the evolving design of TOU tariffs to better support smart charging. This year, we expand the analysis to examine the policy and market development of V2G.

V2G pilots are concentrated in regions with high EV penetration

Vehicle-grid integration pilots are scaling up across China. As of October 2025, the country had deployed 3,832 V2G chargers and aggregated nearly 19.43 GW of flexible EV resources.[34] Including city-level and project-level pilots, 17 provinces had launched vehicle-grid integration demonstration programs. The first batch of national pilots is concentrated in regions with high EV penetration, rather than regions with the highest share of renewable generation (see Exhibit 19). These regions generally have more developed charging infrastructure and a larger base of EV users, providing favorable conditions for early V2G deployment.

Current V2G pilots are primarily testing technical and commercial viability of vehicle-grid integration, with broader deployment expected in the coming years. Most pilots aggregate participating EVs and compensate owners for providing grid services, helping assess the operational impacts of large-scale discharging while exploring sustainable business models. Building on the experience from the first wave of pilots, V2G programs are expected to expand significantly over the next two years.

Exhibit 19 Exhibit 19: EV penetration and the share of renewable generation across provinces



RMI Graphic. Source: NDRC; China Electric Vehicle Charging Infrastructure Promotion Alliance; China Electricity Council; RMI

Local governments are increasingly using financial incentives to support V2G deployment and reduce up-front investment costs. While V2G business models evolve, V2G chargers remain significantly more expensive than conventional smart chargers. For residential users, installation costs are typically two to five times higher, creating a major barrier to adoption. In response, a growing number of municipal, county, and district governments have introduced incentive programs for V2G infrastructure. These incentives are available to both charging service providers and EV owners, and include installation incentives, discharge payments, and grid services compensation (see Exhibit 20). To date, most support has focused on charger installation. Discharge payments and grid services compensation remain less common and are primarily used to support pilot projects and testing activities.

Exhibit 20 **Exhibit 20: Types of V2G pilot incentive policies in selected cities and counties (as of March 2026)**

Region	Installation incentive	Discharge incentive	Grid dispatch incentive
Shanghai	✓	-	✓
Guangzhou, Guangdong province	✓	✓	✓
Pingshan District, Shenzhen, Guangdong Province	✓	-	-
Haikou, Hainan Province	✓	✓	-
Yu County, Yangquan, Shanxi Province	✓	-	-

RMI Graphic. Source: Municipal, county, and district governments; RMI

Three provinces introduce V2G discharge pricing policies; revenues depend on access to peak-price hours

Developing discharge pricing mechanisms is a critical step toward V2G commercialization. As of February 2026, Guangdong, Jiangsu, and Shandong had introduced provincial V2G discharge pricing policies (see Exhibit 21). Two pricing approaches have emerged. Shandong has adopted a market-based model, with discharge prices linked to real-time wholesale electricity prices. Guangdong and Jiangsu use a combination of benchmark coal-fired power prices and administratively defined TOU pricing structures. In Guangdong, discharge prices vary across sharp peak, peak, shoulder, and valley periods through different pricing multipliers applied to the benchmark coal-fired power price. Jiangsu uses a simpler design: only sharp peak periods are linked to TOU pricing, while all other hours settle at the benchmark coal-fired power price.

Exhibit 21 **V2G discharge pricing mechanism design in selected provinces**

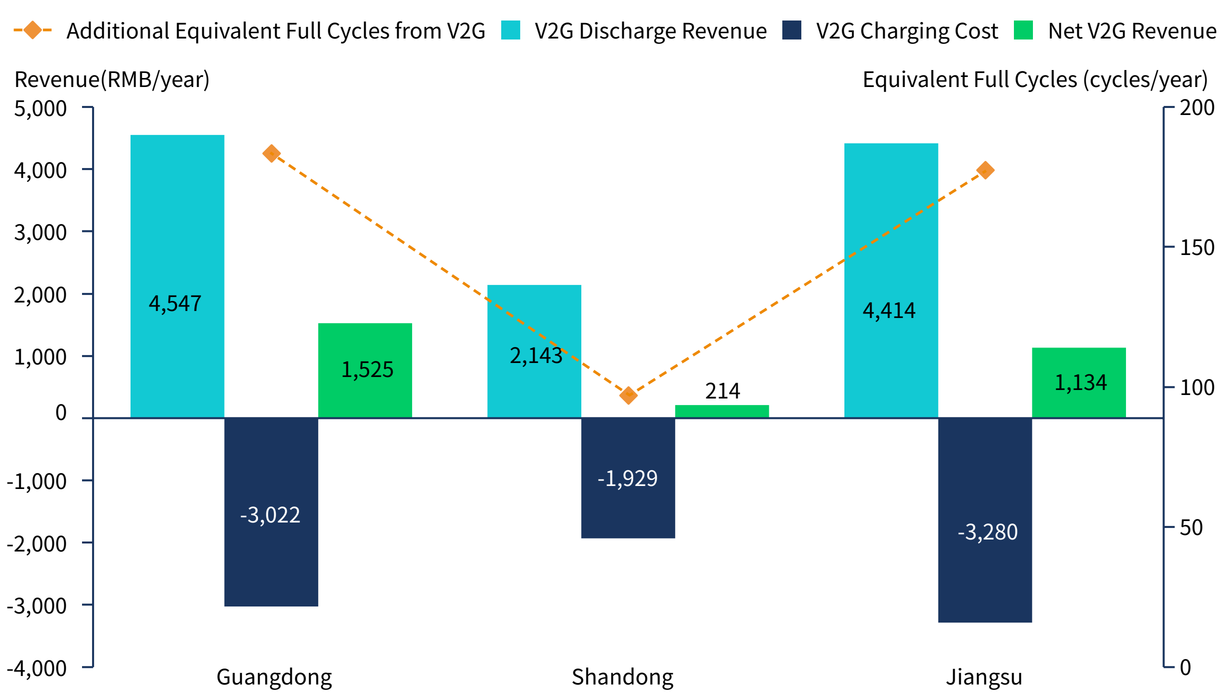
Region	Charger type (commercial/residential)	Discharge pricing mechanism design
Guangdong (Guangzhou and Shenzhen only)	No differentiation	Prices for different periods are determined by applying administratively defined TOU pricing multipliers to the benchmark coal-fired power price.
Jiangsu	Commercial	During sharp peak periods, prices are settled based on the corresponding sharp peak retail electricity price for grid-procured commercial and industrial users at the same voltage level. During all other periods, prices are settled at Jiangsu's benchmark coal-fired power price.
Shandong	Commercial users participating directly in the power market	Settled based on the real-time weighted average generation-side nodal price in the Shandong spot market, while also bearing applicable market operation charges.
Shandong (Jinan and Zibo only)	Residential	Settled at the real-time weighted average generation-side nodal price in the Shandong spot market.

RMI Graphic. Source: Provincial development and reform commissions; RMI

V2G economics are currently more attractive in regions that use a "benchmark coal-fired power price + administratively defined TOU pricing" approach. Based on charging and discharge prices in Shandong, Guangdong, and Jiangsu, we modeled the potential returns from V2G participation for EV owners. For residential users with private chargers, annual net revenues can exceed RMB 1,000 in both Guangdong and Jiangsu under a peak-valley arbitrage strategy (see Exhibit 22). In Shandong, however, discharge prices are linked to real-time market prices. Because average prices during typical discharge hours are relatively low, V2G revenues are considerably lower.

Two factors could affect these results. First, the analysis does not account for additional battery degradation from V2G participation. Under the Guangdong scenario, V2G could add around 188 equivalent full battery cycles per year, potentially increasing long-term battery replacement costs. Second, discharge pricing mechanisms are likely to continue evolving. Over time, market price signals are expected to play a larger role, reducing reliance on administratively defined TOU pricing. As V2G scales up, more provinces may move toward market-linked pricing models like Shandong's. If that happens, V2G returns could become less attractive than those estimated here.

Exhibit 22 **Estimated costs and revenues for residential V2G chargers in Shandong, Guangdong, and Jiangsu**

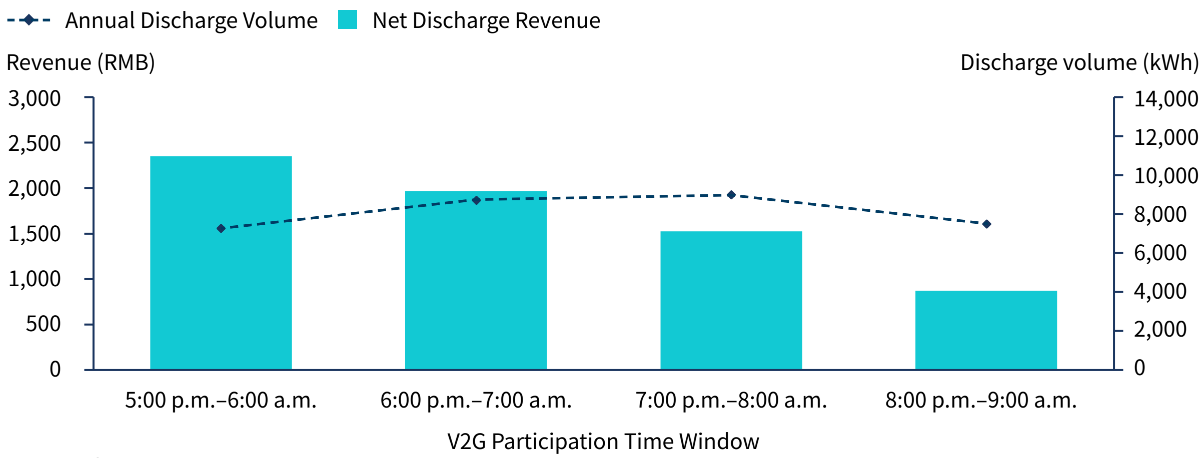


Note: Estimates assume that vehicles participate in V2G four days per week, with discharge periods from 7 p.m. to 8 a.m. and state of charge (SOC) is restored to 90% afterward. Battery charging and discharging efficiency is assumed to be 95%. Vehicle battery capacity is set at 70 kWh, and charger rated power at 7 kW. Average daily driving distance is assumed to be 35 km, with the SOC operating range set between 20% and 90%.

RMI Graphic. Source: RMI

For EV owners, V2G economics depend largely on whether vehicles are parked during high-price periods. Under the same participation duration, greater exposure to peak-price hours translates into higher revenues. In Guangdong, for example, commercial and industrial TOU pricing defines 3–7 p.m. as peak hours, with prices falling after 8 p.m. As a result, earlier participation that captures more evening peak hours generates higher returns. Each additional hour of peak-period participation increases annual revenue by roughly RMB 400. Once discharge periods no longer overlap with evening peaks, revenues decline sharply. Under a participation window of 8 p.m.–9 a.m., annual revenues are around 43% lower than in the base case (see Exhibit 23). More broadly, the economics of residential V2G depend heavily on how well vehicle parking patterns align with local peak-price periods.

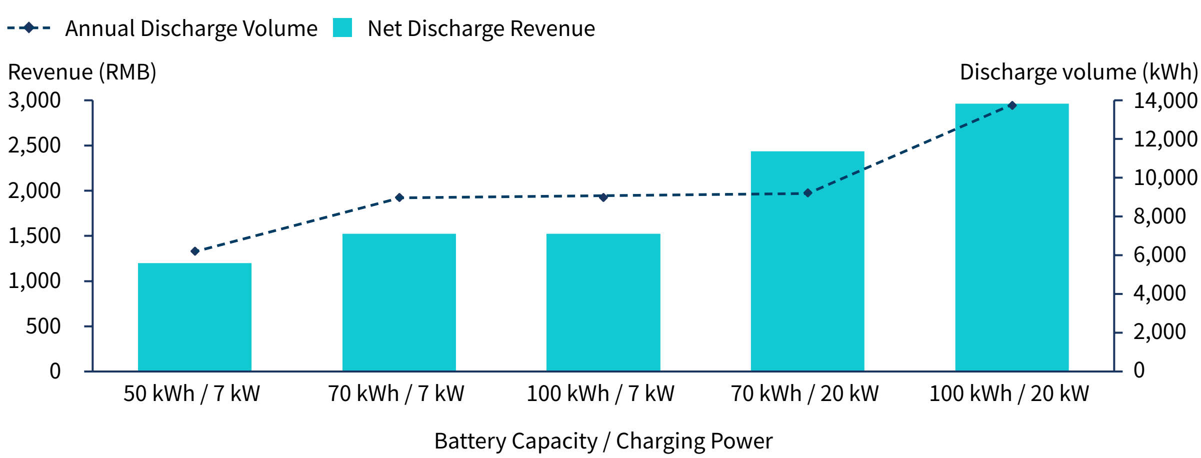
Exhibit 23 **Estimated V2G revenues under different participation time windows (Guangdong)**



RMI Graphic. Source: RMI

Higher-power chargers can significantly improve V2G economics by enabling more electricity to be discharged during high-price periods. Under the same battery capacity, our analysis shows that a 20 kW charger can generate roughly 60%–94% more revenue than a 7 kW charger. Battery size also influences earnings, particularly when paired with higher-power charging equipment. Larger batteries can unlock greater value by supporting higher discharge volumes, while the benefits are much smaller when only slow chargers are used (see Exhibit 24). SOC settings matter as well. A higher minimum SOC leaves less capacity available for discharge, reducing potential revenues. Under otherwise unchanged assumptions, annual revenues under a 50%–90% SOC range are about 30% lower than under a 20%–90% range. By contrast, raising the upper SOC limit beyond 90% provides only marginal additional benefits.

Exhibit 24 **Estimated V2G revenues under different battery capacities and charger power levels (Guangdong)**



RMI Graphic. Source: RMI

Endnotes

1 *Notice on Comprehensively Accelerating the Development of the Power Spot Market*, General Office of the NDRC and General Department of the NEA, April 29, 2025, **https://www.ndrc.gov.cn/xwdt/tzgg/202504/t20250429_1397489.html**.

2 *Annual Report on Power Spot Prices and Revenues by Generation Type (January–December 2025)*, Lambda Power Spot Market, 2026.

3 *Coal Market Analysis for 2025 and Outlook for 2026*, China Taiyuan Coal Trading Center Company, January 27, 2026, **https://mp.weixin.qq.com/s/jwbZC38VquW3sjUHxPzsHQ**.

4 Ziyuan Zhao, “Entering the Power Spot Market 2.0 Era. China Electric Power Enterprise Management,” *Weixin*, January 13, 2026, **https://mp.weixin.qq.com/s/4W9xSt4kpslrgSK5IAnDaw**.

5 Hailong Li, et al., “Implications of the Zero-Price Phenomenon in Heilongjiang’s Power Spot Market for the Energy Transition,” Telecom New Media, January 23, 2026, **https://mp.weixin.qq.com/s/jGX_ybICo_sYL3z_TdVEWA**.

6 “Why Did Spot Prices in Heilongjiang and Fujian Drop Sharply in December?” Lambda Power Spot Market, January 6, 2026, **https://mp.weixin.qq.com/s/eCazJF5hLQdxNvS4woPN7w**.

7 *Notice on Issuing the Guidelines for Market Construction in Regions with Continuously Operating Power Spot Markets*, NDRC and NEA, September 12, 2025, **https://www.ndrc.gov.cn/xxgk/zcfb/tz/202509/t20250912_1400454.html**.

8 *Basic Rules for the Medium- to Long-Term Power Market*, NDRC and NEA, September 12, 2025, **https://www.ndrc.gov.cn/xxgk/zcfb/ghxwj/t20251226_1402666.html**.

9 *Shandong Energy Regulator Promotes User-Side Volume-and-Price Bidding for Participation in the Spot Market*, NEA Shandong Regulatory Office, January 29, 2026, **https://sdb.nea.gov.cn/dtyw/jgdt/202602/t20260202_295233.html**.

10 *Implementation Opinions on Improving the National Unified Power Market System*, General Office of the State Council, February 11, 2026, **https://www.gov.cn/zhengce/zhengceku/202602/content_7057745.htm**.

11 *Basic Rules for the Medium- to Long-Term Electricity Transactions*, NDRC and NEA, July 1, 2020, **https://www.ndrc.gov.cn/xxgk/zcfb/ghxwj/202007/t20200701_1232843.html**.

12 *Notice on Issuing the Guidelines for Market Construction*, NDRC and NEA, 2025.

13 “Announcement by the Anhui Electricity Trading Center on the Release of Wholesale and Retail Price Information for the Electricity Retail Market from January to December 2025,” Anhui Power Exchange Center, January 13, 2026, **https://pmos.ah.sgcc.com.cn:20080/pxf-settlement-outnetpub/#/pxf-settlement-outnetpub/unstructedInfo?infoCodes=jygg&marketId=PHDAH&guid=08881050-c2b9-4591-9d38-80014e81664b&viewWayCode=1002&sourceData=1&operateDate=MjAyNi0wMS0xNA%3D%3D&pidTem=1**.

14 “Notice of the Guizhou Provincial Energy Administration on Issuing the *Guizhou Province 2026 Electricity Marketization Trading Implementation Plan*,” Guizhou Energy Administration, January 20, 2026, **https://news.bjx.com.cn/html/20260120/1480405.shtml**.

15 “Announcement on Soliciting Opinions and Suggestions on the *Shaanxi Electricity Market Rule System (Draft for Comments)*,” Shaanxi Development and Reform Commission, March 18, 2026, **https://sndrc.shaanxi.gov.cn/hdjl/dczj/202603/t20260318_3622625.html**.

16 *Notice on Improving the Generation-Side Capacity Pricing Mechanisms*, NDRC and NEA, January 30, 2026, **https://www.ndrc.gov.cn/xxgk/zcfb/tz/202601/t20260130_1403524.html**.

17 *Notice on Improving Pricing Mechanisms to Promote Local Consumption of Renewable Power*, NDRC and NEA, September 12, 2025, **https://www.ndrc.gov.cn/xxgk/zcfb/tz/202509/t20250912_1400444.html**.
18 *Guiding Opinions on Accelerating the Development of Virtual Power Plants*, NDRC and NEA, April 11, 2025, **https://www.ndrc.gov.cn/xxgk/zcfb/tz/202504/t20250411_1397162.html**.
19 *Notice on Deepening the Market-Oriented Reform of Renewable Energy On-Grid Pricing to Promote High-Quality Development of Renewables*, NDRC and NEA, 2025.
20 Yi Jiang, et al., *Pathways for Resilient Development of Distributed Solar PV in China: Market Outlook for 2026–2027*, RMI, 2025, **https://rmi.org.cn/insights/accelerating-china-distributed-solar-pv-development-report/**.
21 "NEA Holds Press Conference on the Performance of China's Electricity Market Trading in 2025," NEA, January 30, 2026, **https://www.nea.gov.cn/20260130/8f698dfb4ebe4a5d93b5507b6a47d888/c.html**.
22 "NEA Releases Data on the Issuance and Trading of Renewable Energy Green Electricity Certificates in December 2025," NEA, January 22, 2026, **https://www.nea.gov.cn/20260122/4494e983105a4dae9a791611d8e46dcd/c.html**.
23 *Annual Review: Electricity Market Trading in Key Provinces in 2024 (Part II)*, Sihe Technology, February 27, 2025, **https://mp.weixin.qq.com/s/SeCEgHStkBt650sstPvXow**.
24 *2025 Guangdong Electricity Market Annual Report*, Guangdong Power Exchange Center, March 14, 2026, **https://mp.weixin.qq.com/s/wNkMASl6MvswxfcHbdHidg**.
25 "2024 Guangdong Electricity Market Annual Report: Yubo Energy Highlights the Key Points," Guangdong Power Exchange Center, Yubo Energy, March 7, 2025, **https://mp.weixin.qq.com/s/B_sgrOnG9qRWE2oCXN-kwg**.
26 "National Energy Administration: Year-on-Year Increase of 21.45 Times!" NEA, April 5, 2025, **https://www.nea.gov.cn/20250425/6b0abbb1ca1e407bbbaf7f3bacd37c7a/c.html**.
27 "NEA Holds First-Quarter 2026 Press Conference," State Council Information Office, January 30, 2026, **http://www.scio.gov.cn/xwfb/bwxwfb/gbwfbh/nyj/202602/t20260202_948701.html**.
28 Beijing Power Exchange Center issued the *Supplementary Revised Provisions for the Implementation Rules of Green Power Trading*.
29 *Basic Rules for the Medium- and Long-Term Power Market, NDRC and NEA, September 12, 2025,* **https://www.ndrc.gov.cn/xxgk/zcfb/ghxwj/t20251226_1402666.html**.
30 "NEA Holds Press Conference on the Performance of China's Electricity Market Trading in 2025," NEA, January 30, 2026, **https://www.nea.gov.cn/20260130/8f698dfb4ebe4a5d93b5507b6a47d888/c.html**.
31 C*hina Green Electricity Certificate Development Report (2025)*, NEA, April 30, 2026, **https://www.nea.gov.cn/20260515/76a82a7375a942e2ab748b36cf7cc14b/c.html**.
32 "SASAC Issues *Guidelines for Green and Low-Carbon Supply Chain Development of Central State-Owned Enterprises (Trial)*," China Energy Conservation Association, April 7, 2026, **https://mp.weixin.qq.com/s/mYjhgdun5aiiY_QiLZdEXQ**.
33 "Notice on Publishing the First Batch of Large-Scale Vehicle-to-Grid Integration Pilot Programs," General Office of the NDRC, General Department of the NEA, General Office of the Ministry of Industry and Information Technology, and General Office of the State Administration for Market Regulation, March 13, 2025, **https://www.ndrc.gov.cn/xxgk/zcfb/tz/202504/t20250402_1396958.html**.
34 "Transcript of the NEA Fourth-Quarter 2025 Press Conference," NEA, October 31, 2025, **https://www.nea.gov.cn/20251031/7b6f39feb2d24ecb91783e282ed64f75/c.html**.

Shuo Gao, et al., *2026 China Power Market Outlook: 10 Key Trends for Market Players*, RMI, 2026,
https://rmi.org/resources/2026-china-power-market-outlook.

RMI values collaboration and aims to accelerate the energy transition by sharing knowledge and insights.
https://creativecommons.org/licenses/by-sa/4.0/

All images in this report are from iStock unless otherwise noted.

RMI Innovation Center
22830 Two Rivers Road
Basalt, CO 81621

www.rmi.org

© Rocky Mountain Institute, July 2026.
All rights reserved.
Rocky Mountain Institute and RMI are registered
trademarks of Rocky Mountain Institute.