



Resource Adequacy Assessment for the East China Grid: Policy Interventions and Contingent Scenarios for 2030

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Executive Summary

The East China Grid (ECG)—comprising Shanghai, Zhejiang, Jiangsu, Anhui, and Fujian—is one of China’s six regional grids and anchors one of the country’s most economically advanced regions. In 2025, the region consumed about 25% of national electricity while producing about 28% of GDP.

In light of various challenges, including extreme weather and new sources of demand growth, policymakers at the national and ECG levels are facing difficult questions of how to ensure resource adequacy (RA) in a cost-effective way while meeting emissions goals. RA policy frameworks in the country are still evolving from an approach of adding nameplate firm capacity to meet expected demand towards one that balances costs and excess capacity concerns. There is still much work to be done to set up frameworks to ensure the right mix of various supply- and demand-side resources. This requires broader reforms to better assess system needs and align system operations and market rules.

For China’s wider power transition, a transparent, model-based RA assessment is a prerequisite for credible planning and investment. A shared adequacy framework—using explicit reliability metrics and stress tests—can help central agencies, grid companies, and provinces compare policy options on a common basis, avoid unnecessary fossil fuel build-out, and sequence reforms that keep the system reliable while advancing decarbonization.

This paper seeks to help fill this gap. We construct a model of the ECG grid based on careful collection of publicly available data, conduct a medium-term RA assessment for the region in 2030, and consider several policy options to meet demand reliably. The results show that **integrated regional economic dispatch and spot-market unification are the highest-impact levers for RA in the**

ECG. When interprovincial and interregional flows are dispatched economically, the ECG records no non-served energy (NSE) region-wide. **Expanded energy storage helps flatten the ECG load “duck curve”** by providing discharge during sunset periods when solar output declines.

The analysis explores the implications of different coal buildout scenarios on system reliability. We compare a case in which ECG coal capacity remains at 255 GW (operating units plus those completed by 2025) with a 305 GW case (Build New Coal, BNC) that includes planned, approved, and under-construction projects. The results show that **reliability can be maintained without building new coal, provided regional dispatch is unified and flexibility resources are scaled**; coordinated operation can substitute for tens of gigawatts of additional coal that might otherwise appear necessary under siloed provincial planning.

Where economic dispatch remains constrained by MLT’s inflexibilities, adequacy risks become material under stress. In these conditions, the joint deployment of enhanced DR and expanded storage together reduce NSE by roughly one-third versus cases with no adequacy measures, underlining their role as a second-pillar priority where dispatch reform is incomplete.

At the same time, the analysis cautions against treating new coal capacity as the default flexibility solution: building additional coal-fired capacity can crowd out other local flexible resources, leading to higher VRE curtailment rates—particularly in coal-intensive provinces such as Shanghai and Anhui. Economic dispatch alone keeps provincial VRE curtailment rates low, not exceeding 2%, while greater deployment of energy storage and demand response (DR) delivers modest curtailment reductions.

Following on these modeling results, we discuss several specific policy recommendations:

1. Create an officially designated transparent rolling RA assessment process
2. Establish a unified and integrated ECG-wide spot market and economic dispatch approach
3. Eliminate coal-specific compensation mechanisms in favor of marketized mechanisms open to clean energy and storage resources
4. Improve incentives and compensation mechanisms for VPPs and DR
5. Rationalize policy framework for battery storage

Introduction

China's power system is the largest in the world and is facing several major challenges simultaneously. First, coal-fired power, which Chinese policymakers have long considered the backbone of adequacy, is under pressure as the government pursues carbon peaking before 2030 and neutrality by 2060. By 2025, total installed power generation capacity reached 3.89 TW. Thermal power accounted for 1.54 TW (of which 1.27 TW was coal-fired) and renewable energy capacity (including wind, solar, and hydroelectric) was 2.90 TW [1]. Second, the intensity and frequency of extreme weather events are increasing [2]. For example, the drought in Sichuan in the summer of 2022 halved local hydropower generation, while extreme heat in 2025 drove national peak electricity demand to a record level of 1.5 TW [3][4]. Third, manufacturing, the largest electricity-consuming sector in China, together with data centers and electric vehicles, is driving rapid growth in power demand. Fourth, the power sector reform process has been proceeding unevenly, with many initiatives – such as implementation of spot electricity markets – at varying stages of maturity. Fifth, difficulties in the broader economy mean capital may need to be invested more efficiently in the energy sector.

The East China Grid (ECG) – consisting of Jiangsu, Zhejiang, Anhui, and Fujian Province and Shanghai – is an important power sector region and case study that faces versions of the major national challenges. In particular, the impact of extreme weather events on the ECG region is significant and growing. Over recent summers, ECG has faced some of the nation's most severe pressures, contending with multiple extreme stressors. Record heatwaves have driven rapid increases in cooling demand, pushing regional peak load above 442 GW in 2025 [5]; droughts across the Yangtze basin undercut “west-to-east” hydropower transfers into ECG in 2022-2024 [6]; high temperatures depressed photovoltaic

efficiency [7]; and typhoons disrupted coastal infrastructure [8]. New problems have emerged, such as the repeated outages of Zhejiang's Jiaying coal plant—China's second-largest single facility with daily generation exceeding 1.1 TWh—caused by jellyfish blooms in 2024, which may be related to climate change [9]. These events exposed hidden vulnerabilities in system adequacy and operations.

In light of these challenges, policymakers at the national and ECG levels are facing difficult questions of how to ensure resource adequacy (RA) in a cost-effective way while meeting emissions goals. RA policy frameworks in the country are still evolving away from an approach of adding nameplate firm capacity to meet expected demand towards one that balances costs and excess capacity concerns. There is still much work to be done to set up frameworks to ensure the right mix of various supply- and demand-side resources. This requires reforms to better assess system needs and to better align system operations and market rules.

In this paper, we construct a model of the ECG grid, based on careful collection of publicly available data, conduct a medium-term RA assessment for the region in 2030, and consider several policy options to meet demand reliably. Our analysis shows that:

(1) Interprovincial and interregional dispatch unification—pooling capacity and sharing flexible resources such as demand response (DR) and storage—can significantly reduce loss-of-load risks during heatwaves, droughts, and sudden transmission disruptions.

(2) Region-scale balancing during adverse conditions can displace on the order of tens of gigawatts of additional coal capacity that would otherwise be needed under siloed planning, pointing to significant reliability co-benefits alongside cost savings.

(3) Construction new coal units should not be the default option for enhancing system flexibility, as alternatives such as DR and battery storage can be more effective at integrating renewables in many cases. For instance, in Jiangsu, prioritizing DR and storage over new coal expansion reduces renewable curtailment from 3.9% to just 0.3% under extreme stress.

To realize these benefits, we recommend practical policy actions that can be reasonably implemented within the next few years. Achieving these measures would help maintain a reliable power system at reasonable cost and support China's carbon emission goals.

Background

The ECG is one of the six regional grids in China's power system, spanning Shanghai, Zhejiang, Jiangsu, Anhui, and Fujian. The ECG hosts a key industrial and economic hub, consuming about 24% of national power and producing 28.5% of GDP, yet generating only 18.6% of the country's electricity. Consequently, local generation capacities often cannot meet dense urban and industrial demand. Provincial characteristics vary: Shanghai is a large load center with little local generation, of which about 95% is coal-fired [10]; Jiangsu and Zhejiang host large coastal industrial bases but face tight land and resource constraints; Anhui retains coal and hydro capacity and often exports within the ECG region; and Fujian is expanding nuclear and offshore wind but remains exposed to typhoon risks and has a single main external grid connection through Zhejiang. Together, the five provinces form the economic and power-demand core of China's east coast.

Due to its high economic concentration and population density, ECG relies heavily on interregional imports. This supply mix includes hydropower from Sichuan, Yunnan and Hubei; coal generation from northern and northwestern provinces, and growing wind and solar imports from the inland provinces, all delivered over ultra-high-voltage transmission corridors. In the summer of 2023, ECG's interregional imports reached 70.45 GW, covering 20.65% of total regional load at the time [12], underscoring the importance of power exchanges as a safety valve during peak stress periods.

To safeguard this high reliance on external power, China employs a hierarchical regulatory framework that aligns national security standards with provincial-level implementation. At the top of this hierarchy, the National Energy Administration (NEA) has issued mandatory reliability rules, requiring regional grids to maintain

2–5% spinning reserves and a backup capacity margin of at least 10% of peak load [13].

These policies are reinforced by national development priorities—codified in five-year plans—that drive the expansion of ultra-high-voltage (UHV) transmission and the integration of new-type energy storage [14][15]. At the provincial level, the provincial Development and Reform Commissions translate these adequacy and security standards into project approvals, linking local initiatives—such as Jiangsu’s virtual power plant (VPP) pilots or Zhejiang’s peak-shaving compensation scheme—to national adequacy goals.

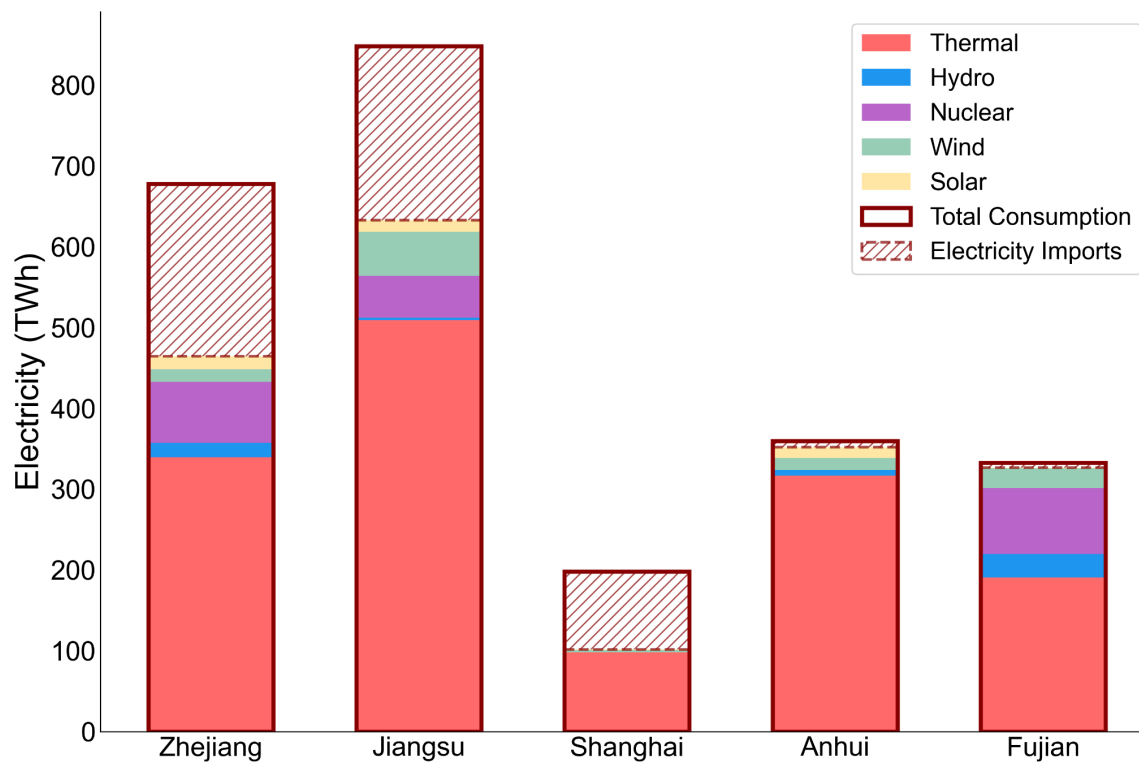


Fig. 1. Electricity supply-demand balance by province in the ECG, 2024 [11].

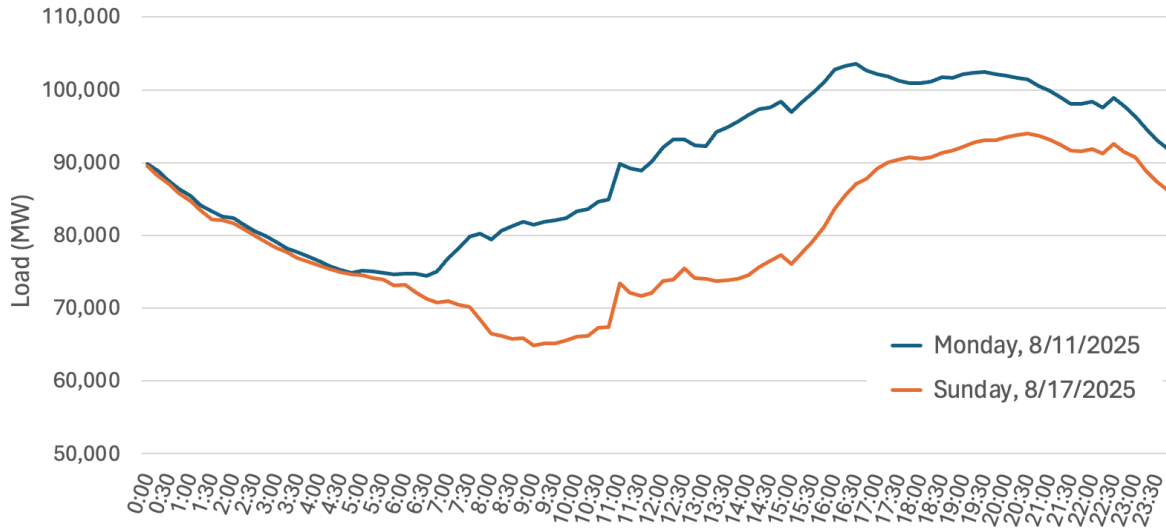


Fig. 2. Recorded weekday vs. weekend load profiles in Zhejiang, August 2025 [16].

Ongoing Policy Reforms in the ECG

Policymakers and stakeholders in the ECG, working within the context of national guidance and requirements, are making ongoing efforts toward policy reform, including steps toward interprovincial coordination in planning, markets, and operations. At the national level, power sector reform policies aim to establish a unified national electricity market by 2030 [17], which provides the overarching vision for cross-border integration. A critical milestone in this evolution was the 2021 introduction of cross-provincial spot trading, a mechanism designed to move beyond traditional long-term contracts. By enabling real-time price signals across provincial boundaries, this market-based approach seeks to minimize renewable energy curtailment and maximize the efficient sharing of resources during periods of system stress [18].

Provincial Electricity markets are emerging in the region but remain limited at the moment. While Zhejiang province’s spot market became “fully operational” as of August 2025, other provinces are still in various stages of “trial operations”. Jiangsu and Shanghai operate spot market pilots, allowing day-ahead and

real-time bidding. In parallel, ancillary service markets have been expanded to include energy storage, industrial load aggregators, EV charging networks, and virtual power plants (used interchangeably with DR in this report), following the “two implementation rules” reform. These mechanisms provide regulation, reserves, and peak shaving, signaling a gradual shift toward market-based tools for flexibility.

These market reforms are mirrored by a significant expansion of the region’s physical and operational connectivity. The “Three Hua” synchronous grid plan (“三华”特高压同步电网) designates that East China, Central China, and North China should form a synchronized “Eastern super-grid” to reduce internal transmission bottlenecks and improve flexibility. Within the ECG, the Yangtze River Delta regional mutual support mechanism (长三角电力区域互济机制) leverages complementary temporal and spatial profiles in demand and generation for adequacy.

Resource Adequacy Vulnerabilities in the ECG

Despite the ongoing initiatives to enhance the interconnectivity and reliability within the region, the ECG is entering a period where traditional planning tools and the current power sector policy and market frameworks are no longer sufficient, as rapid load growth, climate shocks, and structural transformation of the power mix force a shift toward flexibility, diversified resources, and tighter regional coordination.

Structural Asymmetry between Demand Centers and Dispatchable Resources

The ECG has very limited dispatchable resources within its provinces. Nearly one third of Shanghai's power comes from imported hydropower in Hubei and Sichuan, sensitive to annual precipitation. Zhejiang and Jiangsu depend on inflows of inflexible coal units located inland, while their own generation portfolios are increasingly dominated by variable renewables and nuclear plants with limited ramping ability. This structural mismatch means that short-term balancing stress often arises not only during historical peak demand periods (i.e. summer and winter), but is increasingly observed throughout the year when available ramping resources lack sufficient flexibility or response speed to reliably follow intra-day and sub-hourly net load ramps.

As the scale of these interregional connections grows, ensuring their resilience against climate-related variability has become a top policy priority. The 2022 Sichuan drought reduced daily hydropower output by around 50%, sharply curtailing west–east transfers despite available UHV capacity, highlighted the importance of resource diversification and weather-resilient planning [19]. Similarly, the increasing share of wind and solar imports from Northwest China offers a pathway to deep decarbonization, provided they are coupled with local

demand-side flexibility and fast-ramping dispatchable resources to ensure overall system resilience.

Cross-provincial and Cross-regional Import Inflexibility

While intended to guarantee supply and revenue certainty, the dominance of medium- and long-term (MLT) contracts for interprovincial and interregional power flows has resulted in structural rigidity, limiting adaptive response to rapid system shifts. While the interprovincial spot market moved into official operation, it remains in a transitional phase, where standardized rules are still being reconciled with provincial interests, and structural barriers continue to limit trading volume and participant diversity. Although the “spot + MLT” dual-market framework is emerging, interprovincial and regional trades are still evolving slowly. As a result, while the ECG benefits from strong UHV transmission infrastructure and large interregional flows, the current contract structure and market design limit how adaptively these flows can respond to rapid shifts like renewables drop-offs or load ramps.

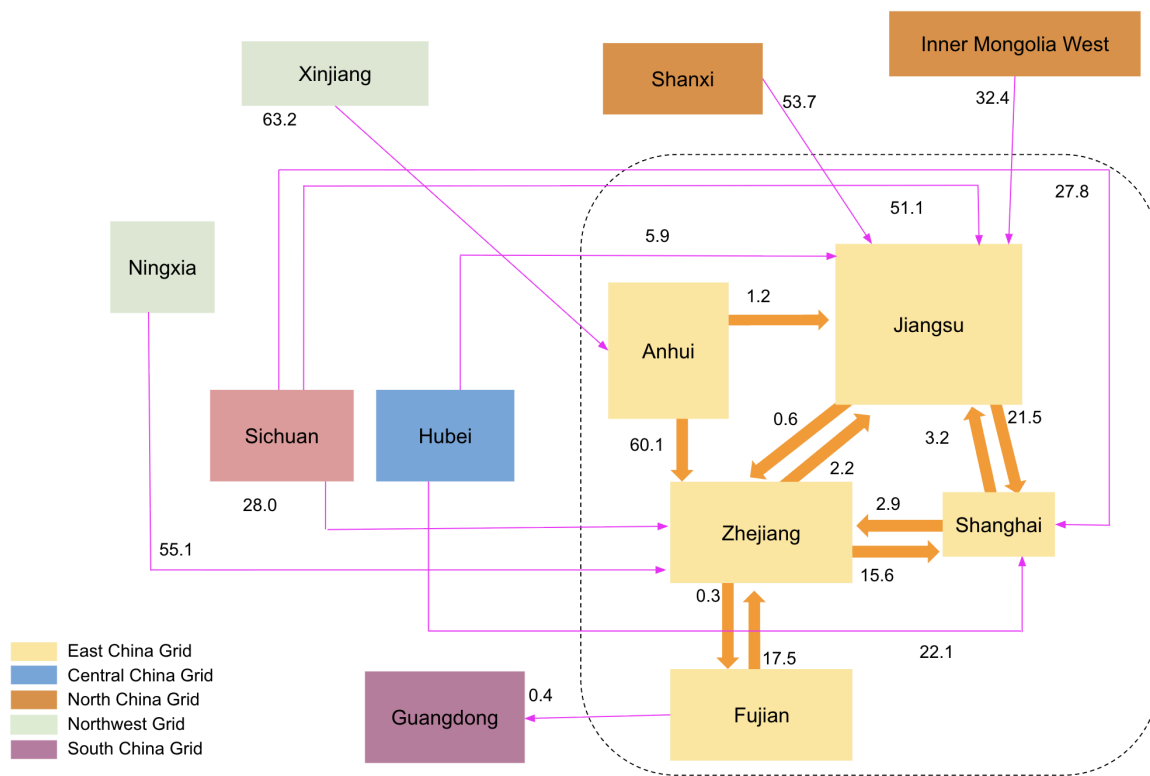


Fig. 3. Yearly interprovincial and interregional transmissions, for the ECG, in 2022. Unit: TWh [20].

Policy Push for Emerging Resources Outpacing Operational Integration

National mandates on storage, DR, and VPPs are ambitious, yet their operational integration in East China remains limited. For example, as of mid-2025, Jiangsu had installed about 7.6 GW of new energy storage capacity, ranking fourth nationwide [21]. Nevertheless, most VPP activities remain at the pilot stage and are typically triggered by administrative orders rather than embedded into market-based dispatch. Further work is needed to expand market integration, enhance operational sophistication, and ensure that VPPs are recognized by system operators as reliable capacity resources during stress conditions.

Under national rules, provinces are mandated to develop demand response (DR) capacity equivalent to 3–5% of peak load by 2025 [22]. However, current programs are not regularly dispatched. Instead of responding to market signals, many DR resources are primarily used as a last resort, activated mainly through infrequent administrative orders still. Since the April policy on accelerating VPP development [23], provinces and cities are consolidating local VPP initiatives. Zhejiang, for instance, has begun integrating VPPs and user-side storage into its demand-side resource pool through issuing China’s first provincial-level VPP operation rules [24], while Jiangsu and Shanghai are incorporating aggregator-based resources into their existing DR programs [25] [26].

Simulation Designs and Insights

This study evaluates how grid operations in the ECG—dispatch of thermal and renewable resources, storage cycling, DR activation, and intra-regional transmission and interregional imports—shift under alternative policy configurations. We do this to quantify the potential reliability benefits (and trade-offs) of policy-driven measures when the system is stressed by adverse weather and demand uncertainty in 2030. We ground our stress level design in empirically observed risk drivers for the ECG (renewable drought and demand growth) and extend them over an hourly operating horizon to reveal persistent strain rather than isolated event hours.

Model and Study Frame

This scenario-based study employs a provincial-node model that optimizes resource dispatch to balance supply and demand in each province, subject to generator, transmission, and policy constraints. We implement a cost-minimizing unit commitment and economic dispatch (UCED) model in Julia/JuMP at hourly resolution for 12 representative high-stress summer weeks (July 1 to Sept 22) of 2030.

The footprint aggregates ECG provinces with explicit interprovincial transmission limits and cross-regional direct-current (DC) flows to capture realistic import/export behaviors. Decision variables include unit commitment and dispatch for thermal and hydro units, charge/discharge cycles for storage, activation of DR, renewable curtailment, interprovincial transmission, interregional imports, non-served reserve (NSR) and non-served energy (NSE) penalized by a value-of-lost-load (VOLL) to evaluate adequacy risks.

The model extends the formulation in prior RA studies [27] with new functionalities for policy-relevant scenario analysis:

- **Grid stress formulation** – a new formulation linking renewable and hydro output reductions with concurrent peak-load increases, allowing stress-test simulation of compound weather–demand events.
- **Non-served reserve (NSR) mechanism** – transforms the hard reserve-balance constraint into a softer penalty formulation, enabling explicit valuation of reserve scarcity and reliability cost.

Scenario Design: System Stress Levels and Policy Levers

We span a factorial of exogenous stressors and RA-related policy levers. The stress levels, presented below, are designed to reflect the compounded effects of extreme weather conditions and load growth. Weather condition 1 (W1) is based on historical weather data from 2018, a representative year with average weather patterns. The hourly wind speed, solar irradiance, and temperature data across all ECG provinces were converted into hourly capacity factors for wind and solar generation. Weather condition 2 (W2) assumes these weather parameters are reduced by half; thus, the hourly available wind and solar generation are also scaled down by 50%. This setting is designed to test the system’s sensitivity to extreme weather and low renewable resource availability. Load growth 1 (L1) is constructed by applying an annual load growth rate of 6% to the load profile published by NDRC, generating the projected 2030 load curve. Load growth 2 (L2) assumes that 72% of the incremental electricity demand is evenly distributed across all hours, while the remaining 28% is concentrated in summer peak hours. Among the four weather-load combinations, W1–L1 reflects the least stressed system condition, while W2–L2 imposes the most challenging adequacy condition, reflecting simultaneous extremes in weather and demand.





Table 1. Stress levels

Stress Level	Weather Condition	Load (TWh) Growth
W1-L1	Weather year 2018	6% annual load growth
W1-L2	Weather year 2018	6% annual load growth, weighted toward peak hours
W2-L1	50% lower wind and solar irradiance than 2018	6% annual load growth
W2-L2	50% lower wind and solar irradiance than 2018	6% annual load growth, weighted toward peak hours

Policy levers toggle four measures off/on: Economic interprovincial transmission (**EcoTx**), Enhanced Demand Response (**EhDR**), Expanded Storage (**EpdS**), and Build New Coal (**BNC**)—individually or in combination. We explore how selecting none, one, two, three, and all strategies affects RA in the ECG.¹ This yields a compact lattice of scenarios in which we compare non-served energy (NSE) outcomes, and operational shifts (imports, curtailment, line utilization), mirroring how international ISO/RTO RA studies pair operability outcomes with adequacy shortage risk.

¹ The study uses 0 to indicate an RA-related policy is “off” and 1 to indicate it is “on.” For example, a policy combination with EcoTx “on” and EhDR, EpdS, and BNC “off” is denoted as EcoTx1–EhDR0–EpdS0–BNC0.

Table 2. Four RA-related policies considered in the research.

	Measure “off”	Measure “on”
 EcoTx	Interprovincial and interregional transmission is dispatched by medium to long-term arrangements	Interprovincial and interregional transmissions are dispatched economically
 EhDR	No DR	5% DR of peak load
 EpdS	PHS capacity: around 45 GW by 2030, considering the operating units and those in construction, with 8-hours duration. Battery: 25 GW, scope in operation and partial “de-rating”, with 2.3 hours duration on average.	Expanded storage: Same for PHS. For battery, double the size to around 50 GW.
 BNC	By 2030, the ECG’s coal capacity is 255 GW, including only operating units and those completed before 2025.	By 2030, the ECG’s coal capacity is 305 GW, including planned, approved, under-construction, and operating units.

* For further details on the input data assumptions, please refer to the Appendix.

Simulation Results

As described above, we simulate the operation of the ECG over a 12-week period during the summer of 2030. The simulation covers four weather–load combinations representing varying levels of system stress, and iterates across 16 combinations of four RA-related policies.

The implementation of economic dispatch serves as a clear dividing line for the level of non-served energy (NSE) as a percentage of demand across provinces. When economic dispatch is in place, the entire ECG region experiences limited NSE, except for a minor shortfall in Fujian. However, once the MLT strategy is applied without the support of more DR, additional storage, or new coal

capacity—that is, under the W2–L2 system stress condition—Zhejiang struggles with the highest NSE share relative to its local load, reaching 3.9%. Moreover, under normal weather and baseline load growth conditions (W1–L1), economic dispatch alone is sufficient for the ECG to achieve zero NSE, even without the other policies.

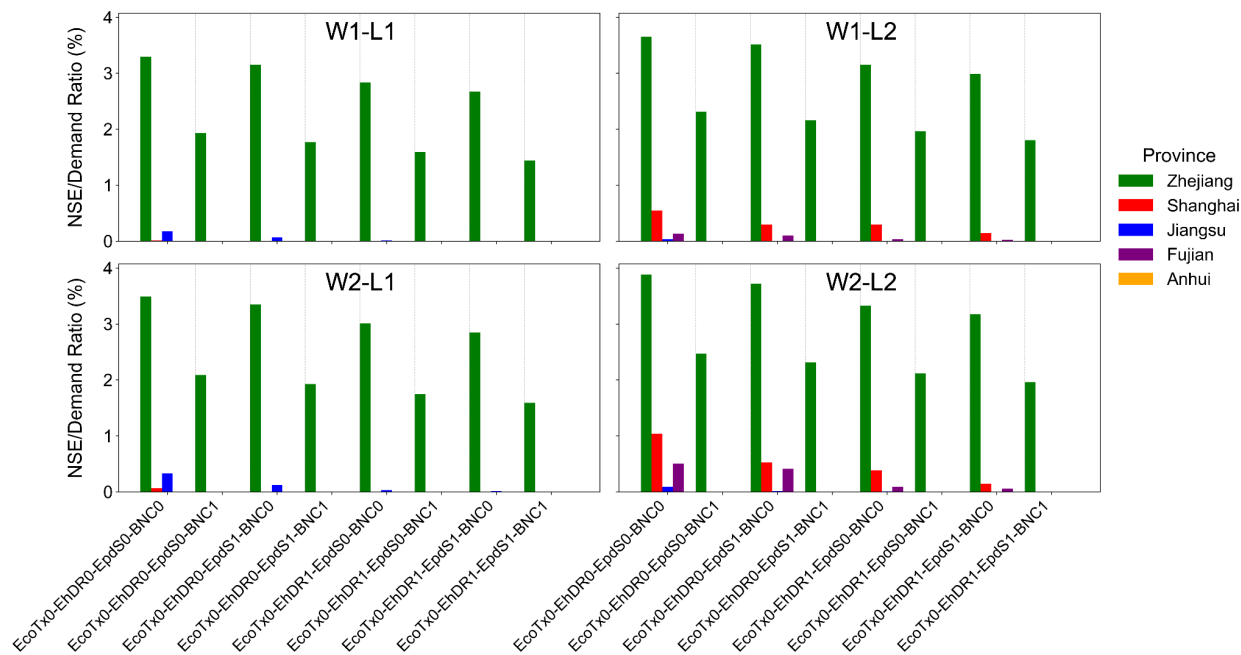


Fig. 4. NSE as percentage of demand for **EcoTx Measure Off** across Shanghai, Jiangsu, Zhejiang, Anhui, and Fujian. Renewable energy availability: W1 (nominal) and W2 (low). Demand: L1 (nominal) and L2 (high).

From a system-wide perspective, under the most stressed system condition (W2-L2), the ECG in the summer of 2030 would experience a maximum NSE ratio of up to 1.7% of total demand, occurring in the EcoTx0–EhDR0–EpdS0–BNC0 scenario. Maximum hourly NSE reaches 53.8 GWh. EcoTx alone—that is, eliminating the distortions to economic dispatch at provincial borders—emerges as the most effective policy change. Without economic interprovincial and interregional dispatch (i.e., system is constrained by MLT contracts), DR and storage expansions remain beneficial; implemented

together, they reduce the NSE by roughly one-third compared with the case without any RA-related policy measures across the four system stress levels. Additionally, if interprovincial and interregional dispatch remains rigid, then additional coal builds based on planned, approved, and under-construction units (BNC is “on”) provide an additional one-third reduction in NSE.

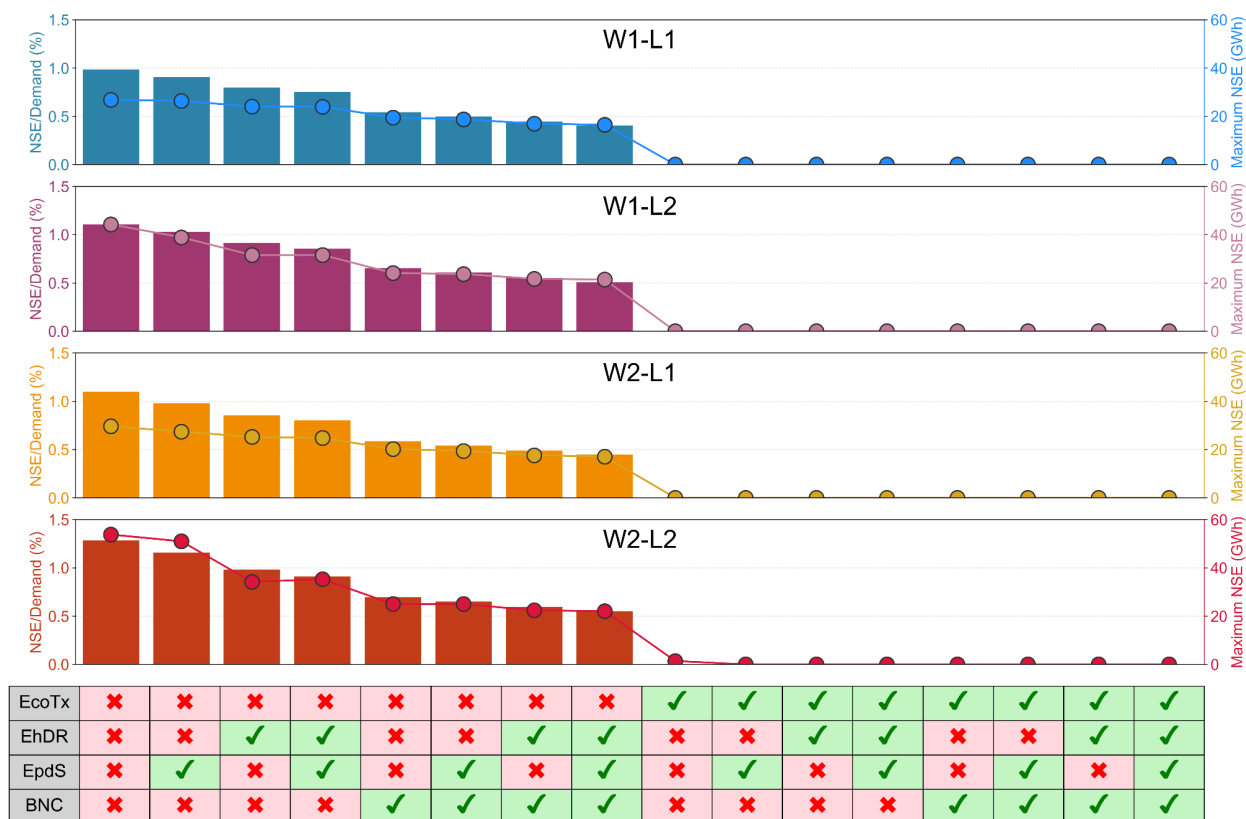


Fig. 5. NSE ratio (total NSE as a share of total demand, bars) and maximum NSE (peak NSE across hours, lines) under different stress levels and policy combinations for the ECG. The table shows different combinations of RA-related policies.

From a load reshaping perspective, 415 GW of solar PV significantly reshapes the ECG’s net load profile, creating a strong “Duck Curve” effect. Even under extreme weather, PV generation supplies about 80 GW at midday, turning the noon peak into a small trough. Hence, the daily load profile of the ECG generally exhibits a unimodal pattern, peaking around 4–5 p.m. At the same time, storage systems begin discharging. The deployment of storage add-ons further helps

mitigate evening peak demand in coordination with residual solar output during sunset hours.

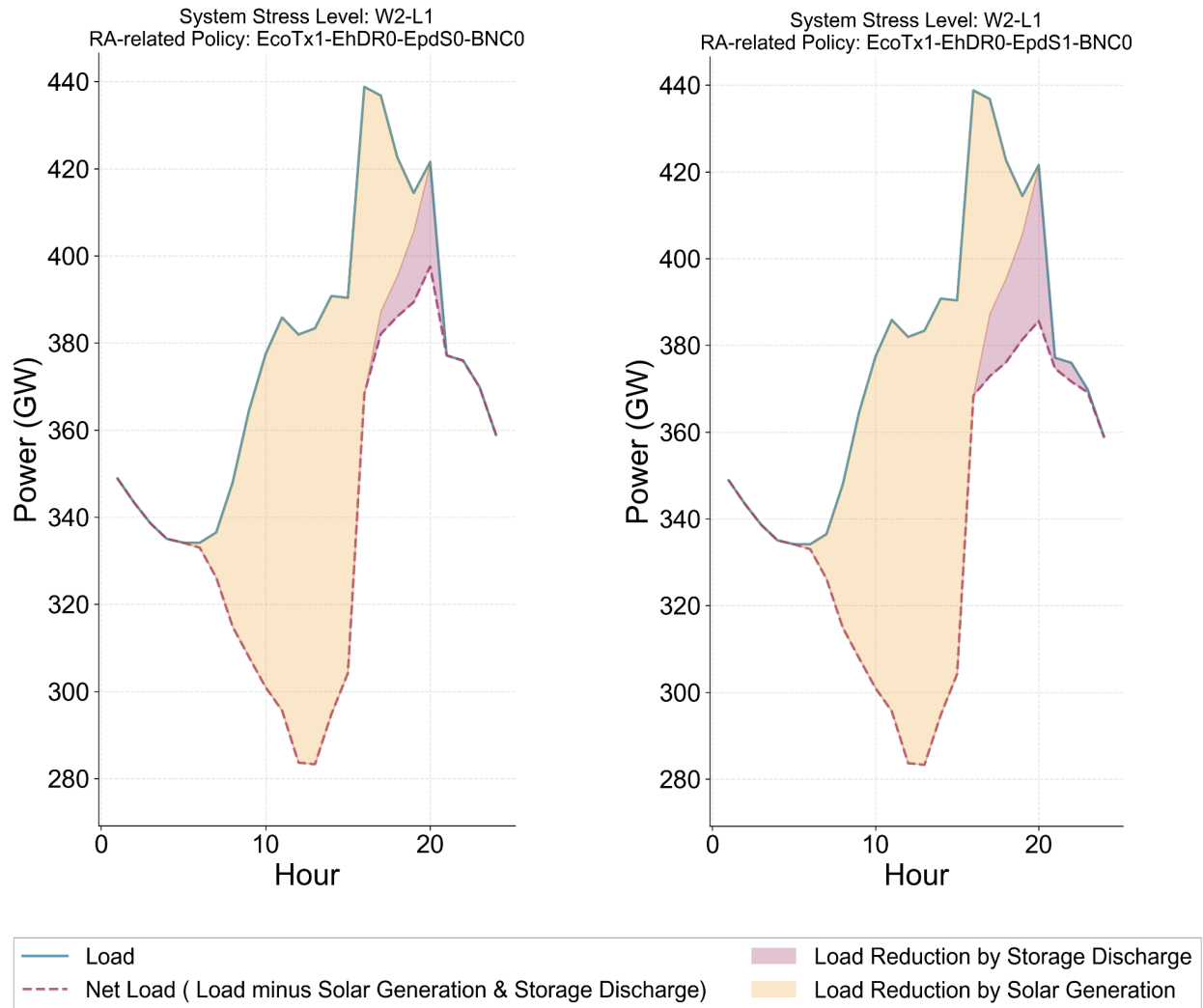


Fig. 6. Load, storage and solar generation for the ECG on July 1, 2030. System stress level: W2-L1. Policy selection: both panels assume no Economic Dispatch, Enhanced DR, or Build New Coal; the left panel assumes no Expanded Storage, whereas the right panel assumes Expanded Storage.

The results demonstrate the significant benefits of enhancing interprovincial and interregional unification of system operations and spot markets, in the service of integrating wind and solar generation. When only the EcoTx policy is adopted, the variable renewable energy (VRE) curtailment rate across provinces in the

ECG remains low, not exceeding 1.6%. Adopting EpdS or EhDR alone enhances system flexibility from a capacity perspective and leads to a modest reduction in VRE curtailment compared with the “None” case. By contrast, building additional coal-fired capacity alone can crowd out other local flexible resources, resulting in a higher VRE curtailment rate than under the “None” scenario in Anhui and Shanghai, where coal-fired generation already accounts for around 90% of total local generation.

Additionally, Shanghai exhibits the highest VRE curtailment rate within the ECG under all system stress levels. This inefficiency persists even under conditions of lower VRE output and higher electricity demand case (W2–L2). In contrast, Zhejiang demonstrates the most efficient utilization of wind and solar resources, maintaining an overall curtailment rate below 0.2% across all simulated stress levels and RA policies.

When interprovincial and interregional economic dispatch is implemented, due to complementary peak demand patterns between Anhui and Zhejiang, Anhui is able to consistently supply relatively low-cost coal-fired power to Zhejiang, leading to a line utilization rate of 60%. Other interprovincial transmission corridors within the ECG are more evenly utilized than in the EcoTx “off” scenario, with utilization around 20% across provinces. For interregional transmission, shifting from the MLT strategy to economic transmission enables nearly all lines to operate at full capacity during peak stress conditions, delivering low-cost power to the ECG. It is important to note a caveat that coherent extreme conditions across exporting and importing regions, such as decreased hydro supply in Central China coupled with increased demand in ECG, can limit some availability of interregional ties.

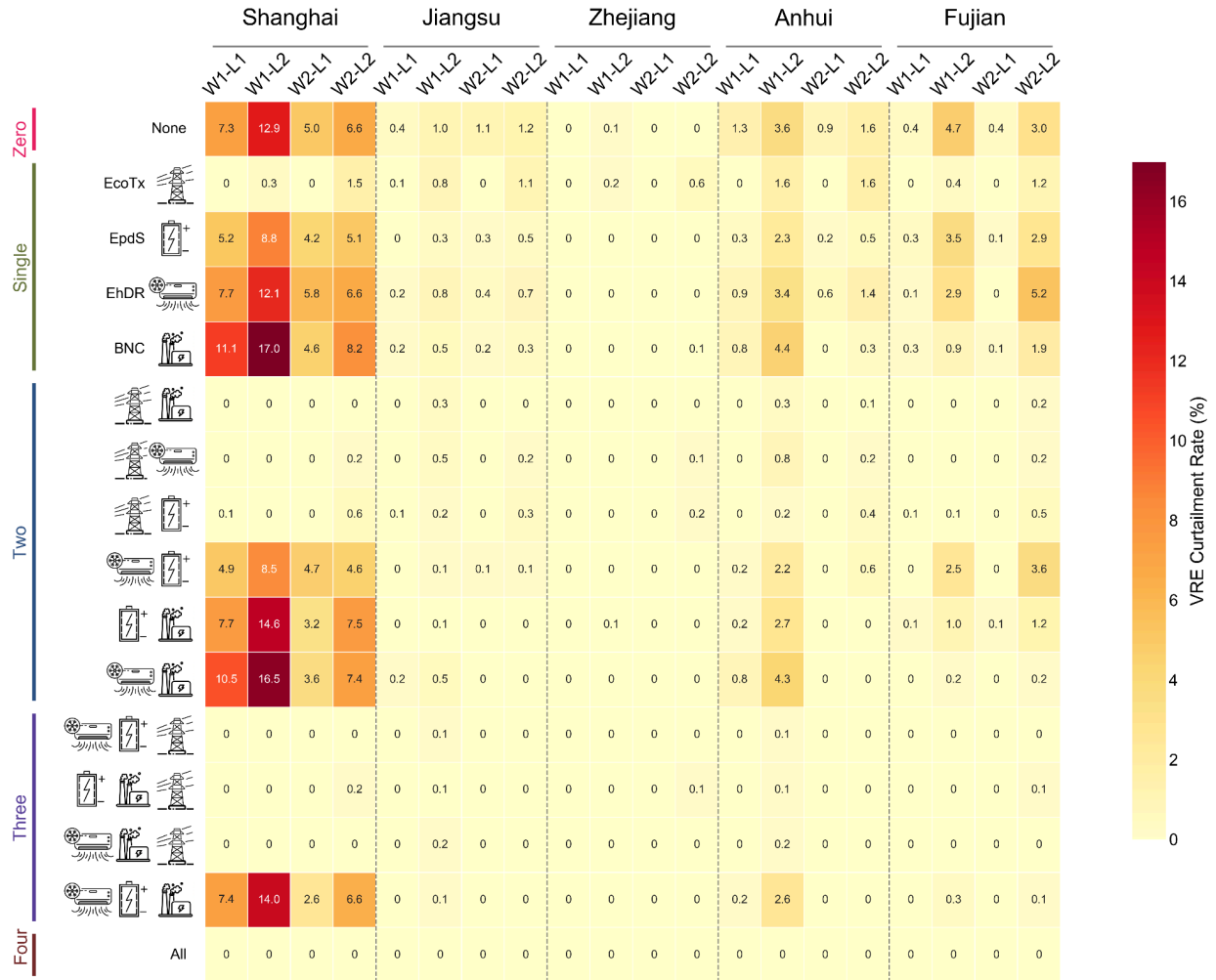


Fig. 7. VRE curtailment rate (%) for each province under different RA-related policy combinations under each system stress level.

Policy Recommendations

Create a Transparent Rolling Resource Adequacy Assessment Process

With the ongoing rapid development of China's new energy system, including fast growth of renewable generation and demand-side resources, policymakers need to establish new and improved RA assessment processes. These will be critical to ensuring system reliability, supporting emissions goals, and controlling costs. While institutions in China already conduct planning and adequacy studies, these efforts are disparate and regulators have not provided sufficient guidance for RA assessments. The lack of a transparent RA assessment process limits the ability of a growing and diverse set of actors – including VPP developers and investors in other distributed resources – to make informed investment decisions. In addition, our scenario results for the ECG indicate that cost-effective resource adequacy without excess capacity build-out is increasingly underpinned by the ability to share resources across provinces and to deploy flexibility options (storage and DR) under compound weather–demand stress, rather than by aggregate capacity alone. We propose:

- **A standardized and transparent process for a rolling RA assessment process should be established by NDRC and NEA**, ensuring the involvement of a broad set of stakeholders. This process should move beyond static capacity margin checks and adopt probabilistic, scenario-based assessments that explicitly simulate regional operations under multi-week heatwaves, hydropower derating, and peak-shifting load growth. A unified assessment process—which regulators should design and regularly review—should be prioritized to serve as the analytical foundation for regional power sector policy, including integration into

five-year planning cycles. Publishing annual assessment results along with data and details about methodology will support new competitive markets with growing numbers of participants.

- **A robust, fair, and transparent capacity accreditation framework should be established as a cornerstone of the RA assessment process.** Accreditation methods must be consistently applied across all resource types—including DR and energy storage—to determine each resource's true contribution, during system stress conditions. It is essential that these methodologies accurately capture the implications of weather and outage rates. They should also explicitly quantify the assumptions of availability of interprovincial transmission capacity and generation resources under severe stress scenarios to ensure all resources are evaluated on a comparable basis. Overall, accreditation should follow a technology-neutral, performance-based approach. Competitive capacity payment mechanisms (see below) should be directly linked to these accreditation results to ensure effective and efficient reliability outcomes [28].

The scenario analyses offered here can be illustrative for regulators in considering officially designated RA assessment processes. However, these are not exhaustive and a more robust process with more granular data and a wider range of parameters and contingencies should be established. International experience can be useful in this regard. For example, the European Association for the Cooperation of Transmission System Operators for Electricity (ENTSO-E), which serves as a continentwide planning authority, conducts RA analysis under different time horizons, including an annual European Resource Adequacy Assessment with publicly available data sets and methodological details that is supporting a reliable clean energy grid [29]. It is important to carefully consider the potential for coherent extreme conditions across exporting and importing

regions, such as decreased hydro supply in Central China coupled with increased demand in ECG, which can limit some availability of interregional ties.

Establish a Unified and Integrated ECG-wide Spot Market and Economic Dispatch Approach

The large potential benefit of better management of interprovincial and interregional electricity flows in ECG, as highlighted in the scenarios above, underscores the importance of harmonizing operations and spot markets at the regional level. Such alignment will be critical for overcoming barriers to integrated dispatch, system efficiency and reliability.

An interprovincial spot market has been operating in the ECG (and broader State Grid) region which, in principle, could encourage more flexible cross-provincial electricity flows. However, its practical impact remains limited, accounting for only 2.6% of total interprovincial and interregional electricity traded in 2024 [30]. To enhance the effectiveness of the interprovincial spot market and the efficiency of operation of the regional grid, we recommend the following measures:

- **Unify the clearing process for interprovincial and provincial electricity markets** to enhance operational efficiency and unlock greater system flexibility. The existing framework, which clears the interprovincial market separately from the provincial market, restricts the optimal utilization of interprovincial resources. Consolidating all bid information from both provincial and interprovincial levels and applying a unified clearing algorithm would enable the development of the most cost-effective and reliable operational plan for the ECG. This unified clearing should explicitly optimize across provincial borders, especially in declared stress periods (e.g. heatwaves and droughts), so that the full potential of external imports and intra-ECG transfers is used to minimize non-served energy.

- **Expanding the volume of interprovincial spot trading.** One approach is to require an increasing share of transmission capacity to be allocated specifically for interprovincial spot transactions. Under current practice, interprovincial spot transactions largely rely on residual transmission capability after priority and MLT schedules are set. Subject to system security constraints and existing contractual obligations, regulators could pilot reserving a limited share of interprovincial transmission capability for day-ahead (and later intraday) spot trading, with any unused reserved margin released after gate closure.

In addition, spot markets at the provincial and regional level are currently hampered by restrictive price caps and floors. For example, Zhejiang Province's spot market features a price cap set at 1200 RMB per MWh and a floor at negative 200 RMB. In contrast, internationally, energy market price caps are typically much higher. In the California Independent System Operator's market, there is a 2000 USD ($\approx 14,240$ RMB) per MWh hard cap, and no price floor. Meanwhile, the Australian Energy Market features a cap of 17500 AUD ($\approx 81,212$ RMB) per MWh. Easing the price limits in ECG's provincial, interprovincial and (eventual) regional spot markets will help send more accurate scarcity pricing signals. The scarcity price signals should be designed to reward fast-ramping and flexible resources that respond during the critical evening peak and multi-day stress periods. These signals will be particularly important for spurring efficient investment in energy storage, DR, and VPPs.

Finally, the current approach to interprovincial transmission pricing in ECG (and China overall) is a barrier to unlocking the benefits of unified regional dispatch and unified regional spot markets. We recommend moving away from the flat per-kilowatt-hour transmission price, which discourages efficient interprovincial trade, toward an approach that encourages efficient use of interprovincial transmission lines. Interprovincial and interregional electricity trading is impacted

by transmission fixed cost recovery mechanisms, which generally recover costs through a fixed per-kWh rate regardless of network congestion or cost differences between provinces. This approach can distort economic dispatch and reduce the efficiency of cross-regional power flows. Transmission costs can be allocated using a more efficient method without distorting economic dispatch. For example, load ratio share allocation distributes costs based on each zone's share of regional peak load and incentivizes reductions in peak demand.

Reform Coal-specific Compensation Mechanisms

Introduced in 2024, the two-part coal power pricing mechanism—consisting of capacity payment and energy price—replaced the single energy-based tariff [31] and has become a central pillar of the profitability model for existing coal-fired power plants. Under the current policy design, it may encourage over-investment in new coal capacity while weakening incentives for the rational and orderly retirement of aging coal power retirement.

First, the current benchmark pricing system for coal power is no longer suitable for the new type of power system. Document 136 (2025) brings increased competition to the RE generation on-grid price and this increases the urgency of need for reform of the coal on-grid price [32]. We recommend building on the 2021 reform [33] that established $\pm 20\%$ coal power on-grid price band by advancing the following measures:

- Accelerate the full liberalization of the benchmark pricing mechanism for coal-fired power.
- Remove the requirement that at least 80% of projected market-based on-grid coal electricity be covered by MLT contracts [34]. Adequacy concerns should not be used as a primary justification for new coal

investment or rigid coal contracting. This rule acts as an administrative support mechanism for coal power generators and increases costs for end users.

Second, the current coal capacity mechanism should be treated as a transitional arrangement, rather than a permanent, coal-centered cost-recovery instrument. Document No. 114 [35], released in January 2026, reaffirmed that provinces must ensure the capacity price recovers no less than 50% of standardized coal fixed costs from 2026 onward, with scope to increase this share further based on local market development and coal utilization hours². However, the current approach remains largely administratively set and non-competitive, and it is not yet structured as forward procurement based on a transparent resource-adequacy (RA) target. We therefore recommend:

- Accelerate the transition—envisaged in the 2026 Document No. 114 [35]—from technology-specific capacity prices to a technology-neutral capacity mechanism, and then to a competitive capacity procurement process (e.g., centralized capacity auctions or bilateral reliability procurement). Competitive procurement should be open to all eligible resources under unified qualification and performance requirements, so that reliability is delivered at least cost and with lower emissions.
- The capacity compensation mechanism should be based on scientific and transparent RA planning, ideally the same officially designated RA assessment process we recommend above. Refined capacity demand calculations should be conducted based on power system reliability standards to determine quantitative targets for capacity procurement,

² In November 2023, the NDRC and NEA issued Document No. 1501, reforming the single-part coal power tariff into a two-part tariff, establishing a capacity pricing mechanism, and requiring that at least 50% of coal power fixed costs be recovered through capacity payments (70% in provinces such as Yunnan and Sichuan). In January 2026, Document No. 114 reaffirmed the implementation of the 50% rule from 2026 and expanded the capacity pricing mechanism to include energy storage.

abandoning the "one-size-fits-all" comprehensive cost recovery model. This mechanism design can avoid problems such as capacity surplus, resource allocation imbalance, unnecessary costs and emissions, and limited system flexibility, ensuring that the capacity compensation mechanism is coordinated with the goals of building a new power system.

Improve Incentives and Compensation Mechanism for VPPs and DR

To support the development of VPPs in China, it is crucial to allow VPPs to receive compensation for the diverse range of grid services that they can provide. VPPs should be fairly rewarded for providing energy, capacity, programmatic DR, and grid support services. This will help the sector reach scale and sustainability [36]. We recommend:

- Improving the design of provincial-level retail time-of-use electricity rates so that they better reflect grid conditions and system costs. This may include expanding the price differentials to more accurately reflect the marginal costs of new generation, transmission, and distribution capacity. This approach will offer clearer price signals to VPPs, incentivizing effective load shifting and enhancing system flexibility.
- Settling VPPs at locational marginal prices rather than broad provincial averages to improve locational price signals and resource efficiency, especially in transmission-constrained areas. While node-level granularity is ideal, sub-provincial zone aggregation may offer a practical compromise, balancing accuracy with feasibility.
- Enable VPP participation in competitive capacity mechanisms, ensuring they can be compensated for their reliability contributions alongside traditional resources.

When combined with distributed solar and wind resources, many forms of VPP (particularly those composed of DR and distributed battery storage) offer cost-effective and flexible capacity compared to traditional thermal resources. To unlock these benefits, VPPs should be actively included as capacity providers in RA assessments. Recent “flexibility planning” guidance issued by NEA encourages comparing flexibility options by cost, and this principle should be extended to any officially designated RA assessment processes, ensuring VPPs are properly valued and compensated for their capacity contributions.

Rationalize Policy Framework for Battery Storage

The scenario analysis in this paper highlighted that additional efficient investment in battery energy storage systems – that is, more investment of the right type in the right places – can play an important role, providing automatic, fast-ramping flexibility in both directions. In particular, we find that, in provinces with high solar and wind penetration such as Jiangsu, expanded storage can reduce renewable curtailment from several percent to below 1% and substantially flatten the regional “duck curve”, while also lowering non-served energy under the most stressed W2–L2 conditions—effects that are not replicated by adding new coal capacity alone.

National policy that was effective in China between 2022 and early 2025 required renewable generation investors to build energy storage in fixed proportion with each investment in renewable energy. Because these assets were not driven by efficient locational incentives, they were often deployed in suboptimal geographic locations. Utilization rates during this period for many of these storage investments were low. The picture is improving since the abolishment of this policy in February 2025 (via Document 136 from NDRC and NEA), although the

effects of inefficient storage investment linger in ECG and elsewhere in the country.

Several of the policy recommendations already mentioned above will also be crucial for rationalizing the policy framework for battery storage – including:

- Improving regional spot market price and locational signals and easing overly restrictive spot market price floors and caps to better reflect locational values of energy storage in congested nodes. By revealing the high-price hotspots, the market provides clear signals for developers to deploy battery assets where they can most effectively mitigate transmission constraints and reduce regional curtailments.
- Improving retail rate design by evolving current static time-of-use (ToU) structures into more dynamic models. Enhanced structures could include real-time pricing (RTP), where retail rates are indexed to day-ahead or hourly spot market prices, or critical peak pricing (CPP), where rates surge significantly during a limited number of hours when the system is under extreme stress, providing a powerful price signal for immediate load shedding or battery discharge.
- In the context of evolving policy, stabilizing expectations regarding capacity payments – in particular, emphasizing a level playing field in the expected capacity market – will be helpful for long-term investment stability. While provinces like Shandong and Guangdong are already moving ahead with capacity payment mechanisms for energy storage, the current framework often segregates coal and storage into separate compensation tracks and the payment for energy storage remains insufficient.

Conclusions

This report evaluates resource adequacy (RA) in the East China Grid for 2030 across different scenarios of load growth, weather patterns, and policy and market design choices. The approach is illustrative of a more robust RA assessment approach that could be adopted by Chinese institutions on a regular basis to determine cost-effective ways of reliably meeting increased demand.

We modeled several policy improvement scenarios: (1) managing interprovincial and interregional electricity flows through economic dispatch, (2) scaling up deployment of VPPs, and (3) strengthening operational controls for energy storage assets.

Key findings include:

- Even if no additional coal units are built after 2025, the ECG can still achieve a highly reliable system (minimal or no outages) in 2030—provided key policy improvements are implemented.
- Of the policy improvements examined, optimizing interprovincial and interregional electricity flows through economic dispatch has the strongest impact on lowering the likelihood of power outages. This is achieved mostly through increased imports from outside of ECG.
- Enhanced control and deployment of energy storage is more effective than adding new coal units for reducing curtailment rates in provinces with high levels of installed renewable energy capacity.
- Efficient investment in energy storage is proven to be an effective option to flatten the region's duck curve.

We make the following specific policy recommendations, in line with supporting the country's dual carbon goals while maintaining reliability and controlling costs:

1. Create an officially designated transparent rolling RA assessment process
2. Establish a unified ECG-wide spot market and interprovincial economic dispatch
3. Eliminate coal-specific compensation mechanisms in favor of marketized mechanisms open to clean energy and storage resources
4. Improve incentives and compensation mechanisms for VPPs and DR
5. Rationalize policy framework for battery storage

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Appendix

This scenario-based study employs a provincial-node unit commitment and economic dispatch (UCED) model that optimizes resource dispatch to balance supply and demand in each province, subject to generator, transmission, and policy constraints.

(1) Network structure

The ECG network representation encompasses all major interprovincial 500kV and above AC connections among Shanghai, Jiangsu, Zhejiang, Anhui, and Fujian, as well as DC interregional links (mostly 800kV HVDC lines) from supply bases such as Ningxia, Gansu, Shaanxi, and Sichuan. The network topology was manually constructed by the authors based on publicly available data, including OpenStreetMap, official statistical yearbooks and grid planning reports, publicly disclosed transmission project information, and satellite imagery (e.g., Google Satellite). Information was cross-validated across multiple sources to enhance consistency and reliability.

Annual province-to-province power transmission volumes are obtained from the Compilation of Electric Power Industry Statistics. To allocate these annual transmissions temporally, we collect time-of-use tariff schedules for each province, identifying super off-peak, valley, flat, peak, and critical-peak periods for each day. Notably, the definitions of these periods typically vary by month or season. We assume that interprovincial transmissions occur only when exporting provinces are in super off-peak, valley, or flat periods and importing provinces are simultaneously in peak or critical-peak periods. The annual transmission to each importing province is first allocated across months in proportion to monthly electricity consumption and is then evenly distributed across the eligible receiving hours within each month. The annual transmission to each importing province is

(2) Electric load in ECG provinces

Hourly electricity demand profiles for each ECG province are derived from the NDRC's 2018 dataset and scaled to 2030. Specifically, provincial load profiles for the ECG are constructed using daily maximum and minimum load data provided by the NDRC, together with representative weekday and weekend hourly patterns. Monthly electricity consumption data for 2018 are used as constraints to generate full-year hourly load profiles for each province. These profiles are then scaled to 2024 based on historical data (the most recent year with complete data). Starting from the 2024 level, a 6% annual growth rate is assumed to project demand to 2030. The projected annual demand is subsequently redistributed across hours to reflect emerging consumption patterns, including base-load demand from data centers and industry, as well as seasonal and time-specific uses such as summer air conditioning and electric vehicle charging.

The resulting 2030 load curves capture stronger evening peaks in the summer months (16:00–20:00, June to September) and broader, flatter profiles during winter (November to February). These adjustments preserve total annual energy use while reshaping hourly and seasonal demand to reflect realistic sectoral growth patterns and load electrification trends within the region.

Two main growth configurations are represented: a moderate peak-demand case, in which 72% of the incremental electricity use is evenly distributed across hours, and a lower-growth sensitivity case with 85% evenly distributed load and smaller seasonal variation. These configurations form the benchmark demand projections and are further modified in subsequent scenarios to explore alternative weather and demand stress conditions.

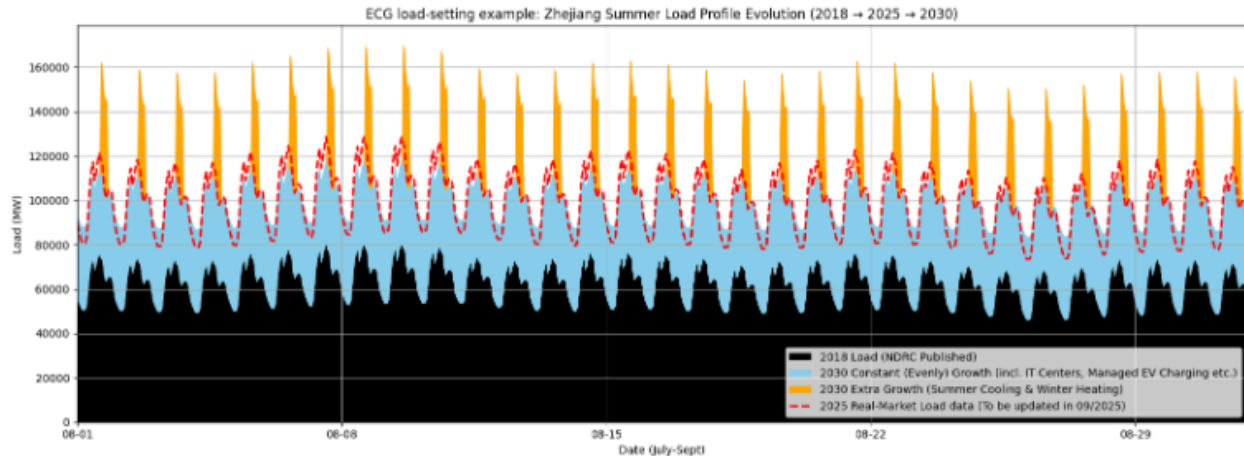


Fig. A2. Illustration of load profile construction for ECG provinces

(3) Generation capacity assumptions in 2030

Installed generation capacities for 2030 are compiled from provincial energy development plans and verified adjustments based on project-level data from GEM and provincial announcements. The five ECG provinces together host a diverse resource mix, with Jiangsu and Zhejiang as the dominant load centers. Provincial distributions vary: Jiangsu alone accounts for more than 30 GW of gas and 150 GW of solar, while Zhejiang combines strong offshore wind and nuclear development. Shanghai maintains limited conventional generation and supports peak demand through imports.

Coal capacity serves as a key policy variable in the scenario design (below). Under the benchmark setting (BNC = 0), we only consider coal-fired power units that are operational or completed by the end of 2025, totaling 250 GW for ECG. While under the increased-coal setting (BNC = 1), we additionally include all units that are under construction or approved, bringing the total to 308 GW³.

³ Source: <https://globalenergymonitor.org/report/boom-and-bust-coal-2025/>, and authors' compilation.

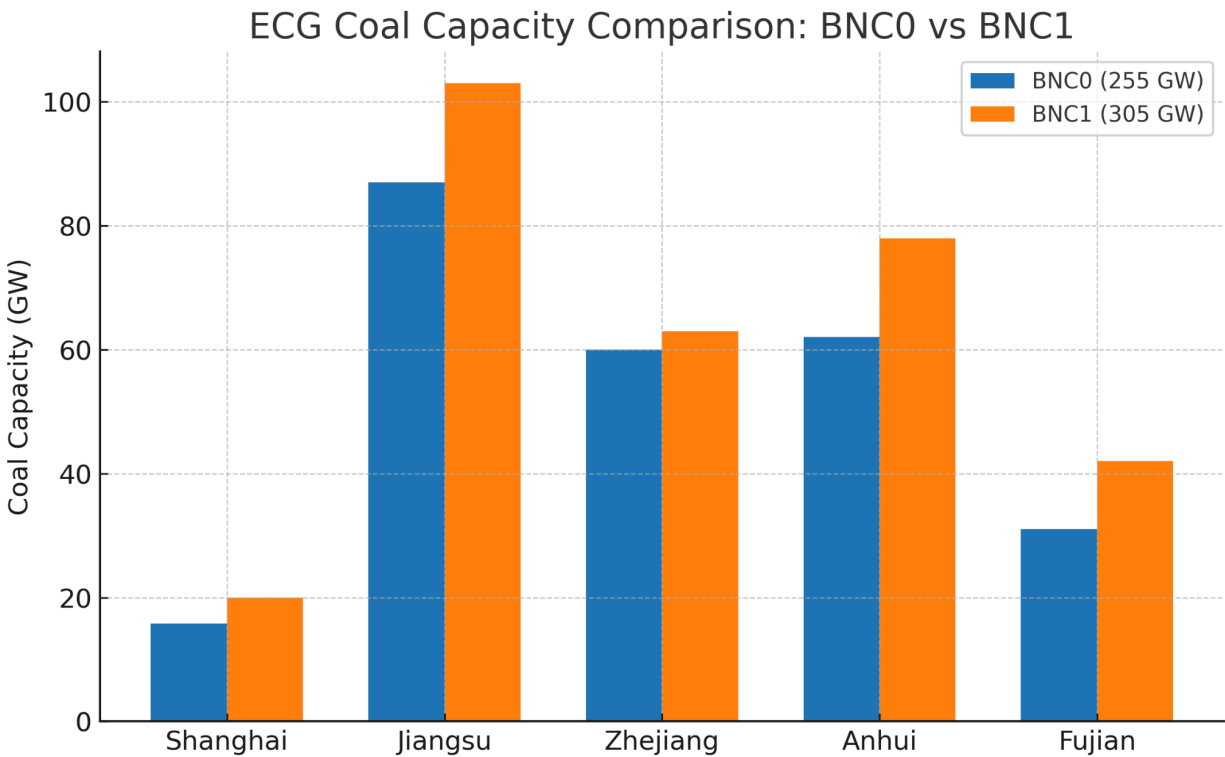
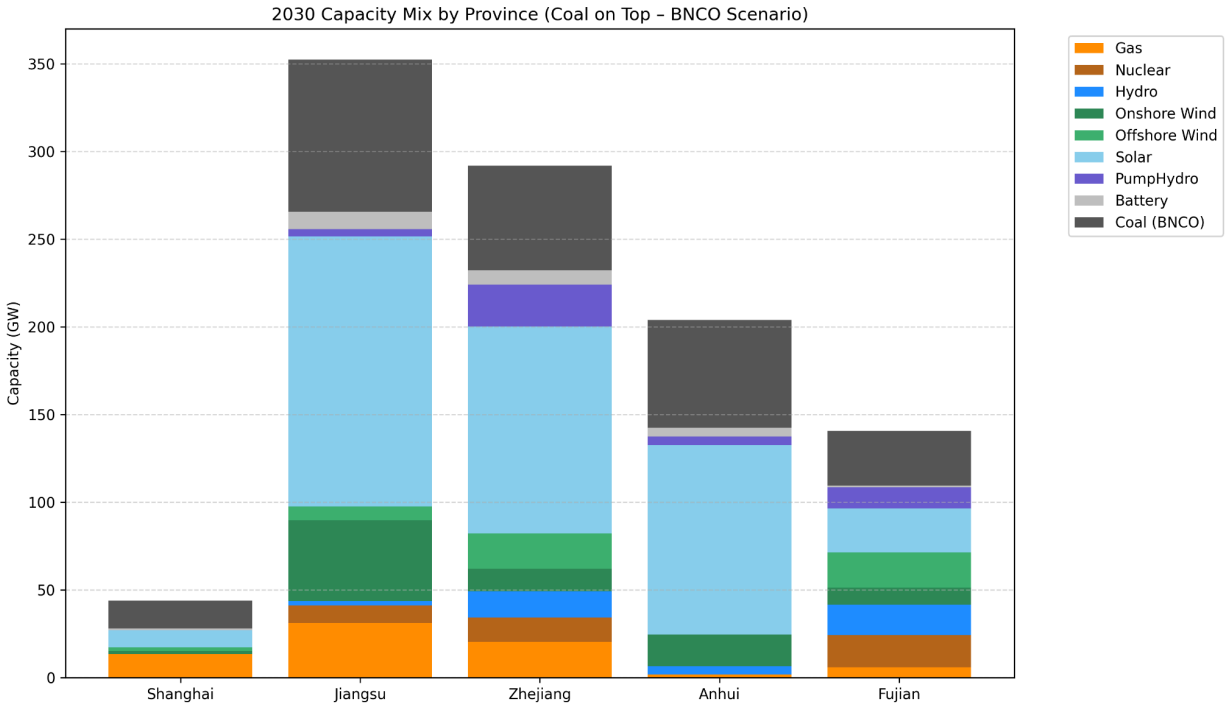


Fig. A3. Up: the generation mix in benchmark (BNC0); bottom: the coal capacity in increased-coal setting (BNC1) case.

Energy storage deployment in China is evolving rapidly, particularly for battery-based systems, with strong policy sensitivity and short investment cycles. Installed capacity can expand by several gigawatts within months under supportive subsidies and favored rules, while project pipelines may stall just as quickly when incentives weaken (as shown in the No.136 document from NDRC⁴).

When EpdS is off, PHS capacity is fixed based on a bottom-up compilation of provincial-level data collected in the second half of 2024, drawing on provincial government disclosures, grid company reports, and publicly announced construction pipelines reflected in GEM database. These sources indicate a substantial volume of projects under construction, with total PHS capacity expected to reach approximately 45 GW in operation by 2030. This capacity is assumed identical in both EpdS-on and EpdS-off cases.

Battery storage capacity under EpdS-off is set to 25 GW (benchmark: around 17 GW by the end of 2025⁵), with corresponding energy capacity (GWh) derived using standard duration assumptions consistent with current Chinese utility-scale practice (2.3 hours). Given the current pace of installation, battery storage capacity in the ECG is likely to exceed the benchmark level in the near term, providing increasingly important RA support. Hence, we assume that when EpdS is on, battery storage capacity is doubled to 50 GW.

(4) Weather data and the renewable profiles

Hourly renewable generation profiles are derived from the 2018 Renewables Ninja dataset, providing consistent wind speed, solar irradiance, and temperature data across all ECG provinces. The year 2018 is selected as a representative meteorological year, as wind speed and solar irradiance levels were broadly consistent with long-term historical averages over the past 15 years. These hourly weather inputs are converted into renewable capacity factors through

⁴ Source: https://www.ndrc.gov.cn/xxgk/zcfb/tz/202502/t20250209_1396066.html.

⁵ https://www.sohu.com/a/798091551_120018660; <https://www.escn.com.cn/news/show-2125311.html>.

calibrated power conversion functions—using turbine power curves for wind and fixed-tilt panel performance equations for solar PV—ensuring spatially and temporally coherent renewable output data. Hydro inflows are stylized using monthly capacity factor adjustments to capture seasonal availability while maintaining constant hourly shapes within each month.

This approach provides realistic weather-driven variability while remaining computationally efficient for large-scale system modeling. However, the method assumes 2018 meteorological conditions as representative of an average year, without incorporating future climate shifts or sub-hourly fluctuations. Consequently, the renewable outputs should be interpreted as baseline production patterns, with scenario variations—such as the scenario that reduces wind and solar generation by 50%—used to explore sensitivity to extreme weather and low-resource conditions.

(5) Cost assumption

Cost parameters are harmonized with the Northeast Grid (NEG) adequacy study and adjusted to reflect East China’s generation mix. Coal prices follow the China Coal Transport and Distribution Association (CCTD) benchmark—averaging 700–750 Yuan/ton for 5500 kcal coal—ensuring that around 90 % of units operate within profitable margins. Gas-fired generation applies 2024 provincial tariff levels (around 0.60 Yuan/kWh). All prices are expressed in 2025 CNY and converted to USD using a 7.2 CNY/USD exchange rate for scenario comparability.

The relative magnitude among cost components reflects the dispatch hierarchy. The non-served reserve (NSR) penalty is set at 800 USD/MWh, lower than the value of lost load (3200 USD/MWh) but higher than the cost of activating low-cost

DR (≈ 420 USD/MWh), allowing the system to tolerate reserve shortfalls before load shedding occurs.

(6) Other benchmark settings

Other benchmark settings define the system's operational reliability and numerical precision. The spinning-reserve requirement is set at 5% of provincial load plus 10% of forecasted wind and solar generation, ensuring sufficient contingency coverage for both demand fluctuations and renewable uncertainty.

The optimization is executed using Gurobi with a 0.8% optimality gap and hourly resolution over 168-hour simulation weeks, balancing temporal detail with computational efficiency. All generation, storage, transmission, and reserve operations are co-optimized under consistent technical and policy constraints.